IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF PUERTO RICO

In re: THE FINANCIAL OVERSIGHT AND MANAGEMENT BOARD FOR PUERTO RICO, as representative of THE COMMONWEALTH OF PUERTO RICO, *et al.* Debtors.[1]	PROMESA Title III Case No. 17 BK 3283-LTS (Jointly Administered)
In re: THE FINANCIAL OVERSIGHT AND MANAGEMENT BOARD FOR PUERTO RICO as representative of PUERTO RICO ELECTRIC POWER AUTHORITY, Debtor.	PROMESA Title III Case No. 17 BK 4780-LTS
THE FINANCIAL OVERSIGHT AND MANAGEMENT BOARD FOR PUERTO RICO, as representative of PUERTO RICO ELECTRIC POWER AUTHORITY, and PUERTO RICO FISCAL AGENCY AND FINANCIAL ADVISORY AUTHORITY, Movants, v. OFFICIAL COMMITTEE OF UNSECURED CREDITORS, Respondents.	**This Court Filing Relates Only to PREPA and Shall Only Be Filed in Case No. 17 BK 4780-LTS**

[1] The Debtors in these Title III Cases, along with each Debtor's respective Title III case number and the last four (4) digits of each Debtor's federal tax identification number, as applicable, are the (i) Commonwealth of Puerto Rico (Bankruptcy Case No. 17 BK 3283-LTS) (Last Four Digits of Federal Tax ID: 3481); (ii) Puerto Rico Sales Tax Financing Corporation ("COFINA") (Bankruptcy Case No. 17 BK 3284-LTS) (Last Four Digits of Federal Tax ID: 8474); (iii) Puerto Rico Highways and Transportation Authority ("HTA") (Bankruptcy Case No. 17 BK 3567-LTS) (Last Four Digits of Federal Tax ID: 3808); (iv) Employees Retirement System of the Government of the Commonwealth of Puerto Rico ("ERS") (Bankruptcy Case No. 17 BK 3566-LTS) (Last Four Digits of Federal Tax ID: 9686); and (v) Puerto Rico Electric Power Authority ("PREPA") (Bankruptcy Case No. 17 BK 4780-LTS) (Last Four Digits of Federal Tax ID: 3747). (Title III case numbers are listed as Bankruptcy Case numbers due to software limitations.)

DECLARATION OF ASHLEY M. PAVEL IN SUPPORT OF URGENT MOTION FOR AN ORDER IN LIMINE PRECLUDING THE OFFICIAL COMMITTEE OF UNSECURED CREDITORS FROM ENTERING EXPERT REPORT INTO EVIDENCE AT THE 9019 MOTION HEARING

I, Ashley M. Pavel, submit the following declaration in support of the *Urgent Motion For an Order in Limine Precluding The Official Committee of Unsecured Creditors From Entering Expert Report Into Evidence at The 9019 Motion Hearing*:

1. I am a counsel with the law firm O'Melveny & Myers LLP, attorneys of record for the Puerto Rico Fiscal Agency and Financial Advisory Authority ("AAFAF") and the Puerto Rico Electric Power Authority ("PREPA"), in the above-entitled cases.

2. Attached hereto as Exhibit 1 is a copy of the expert report that the Official Committee of Unsecured Creditors served on AAFAF and PREPA on October 30, 2019 (the "LEI Report").

I declare under penalty of perjury under the laws of the United States that the foregoing is true and correct.

Executed on November 8, 2019 at San Juan, Puerto Rico.

*/s/ Ashley M. Pavel*____________

O'MELVENY & MYERS LLP
Ashley M. Pavel (*pro hac vice)*
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Exhibit 1

CONFIDENTIAL

Critique of Government Parties' Assertions that the 9019 Settlement Will Not Affect Non-settling Creditors and Will Avoid a Subsequent Title III Filing by PREPA

prepared for the Official Committee of Unsecured Creditors of the Puerto Rico Electric Power Authority

October 30, 2019

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Disclaimer

LEI was engaged by the Official Committee of Unsecured Creditors of PREPA to prepare this report. The opinions and recommendations presented in this report are those of the authors and may not reflect the views of the client or other clients of LEI. LEI's analysis (and the resulting contents of this document) does not constitute investment advice. Modeling results provided and opinions about future market outcomes given in this report should not be taken as a promise or guarantee as to the occurrence of any future events. While LEI has taken all reasonable care to ensure that its analysis is complete, electricity markets are highly dynamic, and thus certain recent developments may or may not be included in LEI's analysis. Furthermore, there can be substantial variation between assumptions and future market outcomes presented by various consulting organizations. Neither LEI nor its employees make any representation or warranty as to the consistency of LEI's analysis with that of other parties. LEI, its officers, employees and affiliates make no representations or recommendations as to the forecasts contained in this expert report. LEI expressly disclaims any liability for any loss or damage arising or suffered by any third party as a result of that party's, or any other parties', direct or indirect reliance upon LEI's analysis and this report.

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List of Acronyms

AAFAF	Puerto Rico Fiscal Agency and Financial Advisory Authority
BCF	Billion Cubic Feet
BTMG	Behind-the-meter Generation
CAGR	Compound Annual Growth Rate
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CDD	Cooling Degree Days
CFP	Certified Fiscal Plan
CHP	Combined Heat and Power
CIA	Central Intelligence Agency
CILT	Contribution in Lieu of Taxes
COS	Cost of Service
DER	Distributed Energy Resource
DG	Distributed Generation
EEI	Edison Electric Institute
EIA	Energy Information Administration
EPC	Engineering Procurement and Construction
ESM	Energy System Modernization
FERC	Federal Energy Regulatory Commission
FOMB	Financial Oversight and Management Board for Puerto Rico
FY	Fiscal Year
GDP	Gross Domestic Product
GNP	Gross National Product
HECO	Hawaiian Electric Companies

IMF	International Monetary Fund
IRP	Integrated Resource Plan
LCOE	Levelized Cost of Energy
LEI	London Economics International LLC
LNG	Liquified Natural Gas
MATS	Mercury and Air Toxics Standards
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
NYPA	New York Power Authority
O&M	Operations and Maintenance
P3	Puerto Rico Public-Private Partnerships (Authority)
PBR	Performance Based Regulation
PIM	Performance Incentive Mechanisms
PPA	Power Purchase Agreement
PPOA	Power Purchase and Operating Agreements
PREB	Puerto Rico Energy Bureau
PREC	Puerto Rico Energy Commission
PREPA	Puerto Rico Electric Power Authority
PROMESA	Puerto Rico Oversight, Management, and Economic Stability Act
PSIP	Power Supply Improvement Plan
PV	Photo-Voltaic
RAB	Regulated Asset Base
REC	Renewable Energy Credit
RFC	Request for Clarification
RFP	Request for Proposal

RFQ	Request for Qualification
RICE	Reciprocating Internal Combustion Engine
RMI	Rocky Mountain Institute
RPS	Renewable Portfolio Standard
RSA	Restructuring Support Agreement
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
T&D	Transmission and Distribution
US	United States
WACC	Weighted Average Cost of Capital

1 Executive Summary

1.1 Scope

London Economics International LLC ("LEI") was engaged by the Official Committee of Unsecured Creditors of the Puerto Rico Electric Power Authority ("PREPA") to provide expert services regarding the motion of the Financial Oversight and Management Board for Puerto Rico ("FOMB"), as the representative of PREPA, and the Puerto Rico Fiscal Agency and Financial Advisory Authority ("AAFAF"), together with PREPA and FOMB, the "Government Parties") to approve a settlement with PREPA's bondholders in PREPA's PROMESA Title III case.

LEI is a global economic, financial, and strategic advisory professional services firm specializing in energy, water, and infrastructure. The firm combines detailed understanding of specific network and commodity industries, such as electricity generation and distribution, with sophisticated analysis and a suite of proprietary quantitative models to produce reliable and comprehensible results. LEI has advised private sector clients, market institutions, and governments on privatization, asset valuation, rate forecasting, deregulation, tariff design, market power, and strategy in virtually all deregulating markets worldwide. Furthermore, LEI has a wide range of experience working on projects related to analyzing electricity sector dynamics and advising on regulatory best practices for island nations, as discussed further below.

LEI was asked to critique the statements that the Government Parties have made in their submissions to the Court that the proposed settlement will not affect the recoveries of non-settling, non-bondholder creditors and that it is very unlikely PREPA will be faced with the prospect of re-entering Title III as a result of the new securities. LEI has conducted this analysis based on the terms of the proposed settlement, the dynamics of the Puerto Rico electricity market, the impact of electricity rates on PREPA's customers, the nature of PREPA's assets, the policy and regulatory goals surrounding the electric utility sector in Puerto Rico, including the plans of Transformation, and other relevant factors.

LEI examined the proposed settlement as contemplated in the definitive Restructuring Support Agreement as of September 9, 2019 ("Definitive RSA") and undertook a thorough review of the current financial condition of PREPA and management's expectations for the near future, including PREPA's 2019 Fiscal Plan, as certified by the FOMB on June 27, 2019 ("CFP2019"), PREPA's 2018 Fiscal Plan dated August 1, 2018 ("CFP2018"), and the Integrated Resource Plan 2018-2019 Revision 2, dated June 7, 2019 ("IRP 2019") submitted by Siemens. LEI also reviewed various documents authored by PREPA and/or its consultants, reports and written materials submitted by other third parties (including the declaration of various witnesses in support of the Joint Motion for Settlement), as well as various regulatory filings, and other documents (reports, news articles, and research papers) related to PREPA and the electricity sector in

Puerto Rico.[1] LEI then conducted additional research on alternatives to utility service, the elasticity of electricity demand, and a cross-jurisdictional review of electricity rates in other island jurisdictions. As a final step, LEI prepared an independent forecast of PREPA's rates in the long term, based on a set of integrated projections for cost of service (revenue requirement) and future grid-connected electricity demand. The purpose of this long term forecast of rates was to capture how PREPA's expected costs of service and the Transition Charge, a non-bypassable charge resulting from the Definitive RSA, would affect consumers' electricity consumption and the longer term financial viability of PREPA's utility business, both of which help us understand whether the Transition Charge is affordable and sustainable over the long term for PREPA. This report (referred to herein as the "Report") documents LEI's analysis and expert conclusions.

1.2 Organization of the Report

The Report is organized as follows:

- Section 0 starts with a summary of the proposed settlement.
- Section 3 provides an overview of key concepts in electricity rate design. Given the proposed settlement affects the final rates that PREPA's customers would pay for electricity service, it is important to understand how rates are set, the key components of electricity rates, and how innovative regulatory practices interact with the basic elements of rate design.
- Section 4 presents a summary and critique of PREPA's forecast of near-term rates, as presented in its certified Fiscal Plans. These forecasts provide important information about the costs of service today and provide a starting position for considering the impact of the proposed settlement on customers and PREPA's operations.
- Section 5 provides an overview of rates in other island-based electricity systems with an investor-owned utility. The experience of other jurisdictions serves as a useful foundation for considering the various issues currently impacting PREPA's cost of service and affecting the evolution of its business and the rate outlook for its customers.
- Section 6 then turns to discuss the perspective of the consumer. LEI identifies the various actions that consumers may take in the future in response to rising electricity rates, including self-supply. In order to put the current situation into context, LEI also considers the "rate burden" for Puerto Rico's electricity consumers.
- In Section 7, LEI presents its rate forecast for PREPA, taking into account the current situation in Puerto Rico (including current and future costs of service, PREPA's current customer mix and expectations for electricity demand in the future, and the Transformation plan), a dynamic electricity demand forecast, and the proposed settlement. LEI's rate forecast is based on its extensive experience assisting utilities and regulators around the world to design rates, observations on what is feasible and best practice, and considering lessons learned from other jurisdictions about rate increases and consumers' response to rate increases. LEI's long run rate projection is vital to

[1] Please see Appendix A, which contains all written documents reviewed and/or relied upon in preparation of this report.

understanding whether there is "room" for additional rate increases to remunerate other creditors and settle other liabilities not part of the proposed settlement.

- In Section 8, LEI provides an assessment of the possibility that the privatization/sale of PREPA's existing generation assets could create value for other creditors not part of the settlement.
- Finally, Section 9 contains LEI's conclusions.
- In addition, LEI provides details about its calculations and assumptions underpinning its modeling and analysis in the Appendices.

1.3 Observations and Key Findings

PREPA is in a difficult financial and operational situation. Its current rates are relatively high as compared to utility rates across mainland US jurisdictions, and especially given the poor quality of service. Moreover, the full costs of providing power to electricity customers are not being met by revenues collected from paying customers. As per the latest audited financial statements, PREPA has over $15.6 billion of debt and other liabilities, but the book value of its assets totals only $9.6 billion.[2] Currently, regulatory-approved rates do not include any meaningful repayment of this legacy debt. The largest number of PREPA's customers are residential consumers, many of whom live within or below the official poverty line. Electric utility bills can represent a significant portion of a household's disposable income, creating an unsustainable "energy burden."

Hurricanes in 2017 crippled the island's economy and devastated PREPA's assets. Hurricane Maria caused power outages to nearly 100% of PREPA's customers in Puerto Rico. Many of PREPA's customers had no electricity for weeks or even months[3] and a large portion of the power grid was damaged.[4] Subpar operating practices and the generally run-down condition of the network and generation assets contributed to the difficult recovery. In 2018, the government of Puerto Rico asked for significant Federal disaster recovery funding, not only to restore the electricity system to pre-hurricane conditions but also to improve (harden) the system. Stakeholders have universally recognized that the restoration of the PREPA system to pre-hurricane levels is not a long-term viable solution. However, creating an electric utility system

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[2] Financial data based on Statement of Net Position (Deficit) from PREPA's Independent Auditors' Report, Audited Financial Statements, and Required Supplementary Information, for the year ended June 30, 2017. It is important to keep in mind that the book value of assets is not the same as the market value of the assets. Moreover, this book value is from a period of time before the hurricanes, and therefore does not reflect the current condition of PREPA's assets.

[3] Department of Energy. "Situation Reports." <https://www.energy.gov/ceser/downloads/hurricanes-nate-maria-irma-and-harvey-situation-reports>

[4] Although the extent of damage has been disputed, testimonials from power restoration efforts suggested a crippled system (see, for example: Office of Cybersecurity, Energy Security, and Emergency Response. "More WAPA Responders Assist in Power Restoration after Maria." September 29, 2017. <https://www.energy.gov/ceser/articles/more-wapa-responders-assist-power-restoration-after-maria>. The New York State Utility Contingent Emergency Response to Hurricane Maria's "After Action Report" from August 2018 also documented the extent of damage, noting that "[t]he combined effects of Irma and Maria led to a collapse of the electric power grid across the entire island by causing significant damage to key segments of the transmission system and approximately 75% of the distribution system; as well as substation damage due to high winds, mudslides and flooding" (*see* https://www.nypa.gov/-/media/nypa/documents/document-library/news/2018-after-action-report-hurricane-maria.pdf).

that can be both resilient and accommodating to ambitious renewable energy policy goals is costly. The amount of additional investment required in Puerto Rico is significant, as discussed in this Report, and it is uncertain whether the Federal government will continue to pay for or subsidize the costs of all necessary investments.[5] If the Federal government will not subsidize such investment, PREPA's customers (or Puerto Rico's taxpayers) will need to pay for such investments.

In 2018, the Puerto Rico government announced plans to privatize PREPA, which they referred to as the "Transformation." Privatization is intended to help drive operational efficiency gains and reduce costs of operation. Experience with the privatization of electric systems in other parts of the world provides a pragmatic set of lessons: reduction in controllable costs is possible, but it takes time and typically occurs gradually. Privatization will also require that commercially reasonable compensation be paid to private operators and service providers. Such compensation will not be small given the complexity of the PREPA system, the risks of operating in Puerto Rico (or, for that matter, general operating risks for any island power grid), and various practical and political challenges for a private operator given the many decades of political intervention in the operations of PREPA to date. Compensation of an operator will need to be recovered as part of the cost of providing electricity service and will flow through to rates. As such, LEI believes that rates will need to rise from current levels to accommodate recovery of all such costs of service.

In 2019, legislation was passed in Puerto Rico to mandate a goal of 100% generation from renewable resources by 2050. Even before the hurricanes, Puerto Rico had ambitious goals to increase its renewable generation that it was not close to meeting. The premise behind these policy mandates is that renewables would reduce the island's exposure to escalating global fossil fuel prices and reduce the variable costs of producing electricity. However, achieving the renewable mandates will require significant generation investment (and supporting transmission and distribution ("T&D") investment). PREPA hopes to attract private capital to fund this investment in renewable generation, but private capital will need to be compensated in customer rates. Although capital costs of renewables are coming down, they are still significant. Furthermore, the precarious financial condition of PREPA will raise the cost of financing for such investments. Ratepayers will need to pay for these renewable investments through long-term power purchase and operating agreements ("PPOAs"), which will need to be rolled into customer rates. The costs of the PPOAs may not be completely offset by reduced use of fossil fuels. If so, rates will need to rise from current levels.

PREPA, the FOMB, and certain bondholders have proposed a settlement to restructure certain portions of legacy debt. Legacy debt is almost entirely excluded from current rates, so this charge would be an addition to current and going forward costs of services. As contemplated in the settlement, the current bonds would be exchanged for new securities, which will be funded through a non-bypassable charge on all electricity customers' bills. The

[5] Central Office for Recovery, Reconstruction and Resilience ("COR3") in its *Transformation and Innovation in the Wake of Devastation: An Economic and Disaster Recovery Plan for Puerto Rico,* has said that a system that would accommodate 40-60% renewables may cost as much as $90 billion. PREPA has only budgeted $16.4 billion for transmission and distribution system ("T&D") capital investment in the next 10 years. Page 218 and 219.

non-bypassable charge, referred to as the "Transition Charge," will be 2.77 cents/kWh in the initial years, but will rise to 4.55 cents/kWh (and that level of Transition Charge will remain fixed for the remainder of the term of these new securities). The nominal term of these new securities is 47 years; in other words, customers will be paying for this settlement for several decades. The Transition Charge will increase the rate paid for electricity by every customer on the PREPA system. The only way to avoid the Transition Charge is for a customer to leave the PREPA system by disconnecting from the grid entirely. By several accounts, it is already cost-effective for some customers to disconnect from the utility system (and some have already done so).

Based on LEI's quantitative analysis, the imposition of the Transition Charge will speed up the decline in energy demand as some customers decide to consume less electricity and/or choose to leave the PREPA system altogether. This will exacerbate the energy burden on remaining customers, many of whom are likely to be lower income residential customers with no feasible alternatives but to reduce their electricity consumption and continue to take service from the PREPA system. In contrast to the declining trend in total electricity consumption, PREPA's total costs of service are not expected to decline. Such a situation would threaten the going forward economic viability of the PREPA system over the medium and longer term. According to LEI's conservative Base Case forecast from Fiscal Year ("FY") 2020 through FY 2047, PREPA's rates (in nominal terms) will need to rise by an average annual rate of 5.0% per year in order to recover PREPA's total cost of service and the Transition Charge, and given LEI's forecast of electricity demand. Even if PREPA can limit all future T&D investments beyond FY 2029, rates will rise an average of 2.9% each year – materially higher than the expected rate of inflation. The rising cost of service will translate directly into higher rates. However, the rate impacts will not end there. Customers will also seek out ways to reduce their electricity consumption and/or to invest in off-grid alternatives – some consumers may even resort to stealing electricity service (or not paying for it). This is likely to decrease total electricity volumes consumed and paid for on the PREPA system. Indeed, LEI projects that annual electricity consumption will fall by 4.2% per annum from current levels through FY 2047, resulting in a cumulative 70% reduction of the total volume of electricity sold and billed for by FY 2047 as compared to current levels.[6] Given that most of PREPA's costs are fixed, such a reduction in electricity sales will mean higher rates for remaining customers.

The imposition of the Transition Charge will accelerate and amplify challenges to the sustainability of PREPA's utility business. It will speed up the decline in electricity demand. Customer defection from the PREPA system will, in turn, exacerbate the energy burden on remaining customers taking service from PREPA (lower income customers who will not be able to afford the increasing rates), potentially creating a vicious cycle that intensifies and creates difficulties for PREPA. This "adverse selection" problem may undermine PREPA's ability to achieve its policy goals, including clean energy and resilience. All-in-all, policymakers and PREPA are likely to face difficult tradeoffs in the future. As their counterfactual, the

[6] Siemens, which was retained to prepare the Integrated resource Plan for PREPA's regulatory submission to the PREB, forecasts a similar reduction in electricity volumes in IRP 2019 (nearly 50% by 2038, the last year of their forecast timeframe). Please also refer to Figure 55 on page 122.

Government Parties posit a scenario in which PREPA raises rates to pay all required debt service on the existing legacy bonds. However, given what is know about PREPA's current circumstances and prognosis for the future, it is unrealistic to presume that PREPA could do this. As such, the "savings" to PREPA (and its customers) that the Government Parties estimate in their evaluation of the RSA are overstated.

PREPA's ability to generate value for creditors other than the bondholders involved in the settlement is contingent on the electricity consumers' ability to pay <u>even higher</u> rates. Given LEI's projection for future rates, inclusive of the Transition Charge, there does not appear to be any headroom to further raise rates to fund other surcharges for the repayment of remaining legacy liabilities.[7] Under such a rate-constrained environment, the potential sale of PREPA's existing generation assets probably will not also create additional value to repay creditors.[8] PREPA's assets are relatively old and some will require material investment in order to maintain their operational capability going forward, as discussed further below. The sale price of any generation asset will depend on how much revenue that asset can earn through future operations. The amount of revenue earned will be impacted by the condition of the asset (and whether it will receive additional capital investment to remain operable) and the level of output that can be generated by the asset.

PREPA's existing generation assets have been poorly maintained and will require capital investment. Capital investments will need to be funded out of the revenues, leaving a small profit margin for the new operator. If the contracts for these assets remunerate the operators based on the utilization of the assets, there is an additional concern and risk. Given PREPA's plans for new renewables and in the face of declining electricity demand, there is a real possibility that many of existing fossil fuel-fired generation assets will see their utilization rates (capacity factors) decline, which would further reduce contracted revenues.[9] In other words, the profit margin, or income, generated by the assets is likely to be limited by the condition of the assets and their performance going forward. In addition, PREPA's ability to raise rates will also indirectly affect the size of any profit margins that generation operators would earn. Private operators will also be concerned with the credit risk they face with PREPA as a counterparty under a long-term agreement. These are the factors that buyers will consider in their purchase price for these assets, or in their negotiation of an operating agreement with PREPA. For all these reasons – the current condition of the assets, the low possibility for rates to

[7] PREPA has suggested in CFP2019 that it may hire an independent, third-party operator for its existing generation assets. LEI has not considered such an arrangement directly in its rate forecast as there is insufficient information about an arrangement of this nature. Puerto Rico's Private-Public Partnerships Authority would need to run a competitive procurement to find such an operator(s). Moreover, a third-party operator would require a fee or profit margin to take over the obligation of operations. Based on LEI's rate forecast, electricity consumers in Puerto Rico may not be able to afford to pay for such an operator.

[8] The lack of substantial market value has also been noted by one of the leading politicians in Puerto Rico. Senator Larry Seilhamer, in a radio interview in early October 2019, disclosed that the outright sale of PREPA's generation assets has been "dropped due to a lack of market interest." Source: Reorg Research, Inc. "New Advisory Contracts Highlight Key PREPA, Fiscal Reporting Issues" October 9, 2019.

[9] PREPA would rationally only offer contracts and pay for generation capacity that can provide cost-effective energy and/or reliability value to the system. As newer, better performing units comes online, PREPA's older generation units will be dispatched less frequently and their reliability contribution to the system will decline. The obsolescence of the units, with time, would be reflected in the contract term (and pricing).

increase to compensate buyers for their purchase price, and the operating risks for the assets – LEI believes that the sale price of existing generation would be very limited.

In summary: Although the Transition Charge will not itself cause the subsequent failure of PREPA, it will likely accelerate negative outcomes for PREPA and its customers, when combined with all the other costs of service that PREPA will need to pass on to its customers.[10] In reaching this conclusion, LEI notes that it has not been provided with a rate sustainability analysis from any of the Government Parties. Absent such analysis, it is difficult for LEI to understand how the Government Parties can believe, as they state in their submissions, that PREPA is not likely to reenter Title III in the future if the settlement is approved. It is similarly difficult to understand how the Government Parties can allege that the settlement will not impact non-bondholder creditors, absent a study or analysis to the contrary. Indeed, as detailed in this report, it is LEI's view, based on available information, that PREPA has no, or very limited, ability to generate a recovery for other creditors, either through an additional rate surcharge, a sale of generation assets, or otherwise.

1.4 Qualifications

1.4.1 Julia Frayer, Managing Director

Julia Frayer, Managing Director at LEI, oversaw the preparation of the analysis contained in this Report. She was supported by numerous members of the LEI teams in Boston, Toronto, Chicago, and Hong Kong. Ms. Frayer has more than 20 years of experience providing expert insights and consulting services in the power and infrastructure industries. She specializes in the analysis and economic issues related to energy infrastructure assets, including transmission and distribution network utilities, regulated and deregulated retail businesses, gas transportation networks, generation businesses and power marketing firms. She has also worked in the water and wastewater sector. Although based out of the Boston, Massachusetts office, Ms. Frayer has worked extensively in the US, Canada, Europe, and Asia.

As Manager of LEI's quantitative, financial and forecasting practice areas, Ms. Frayer and her team of economists, mathematicians, engineers, and policy analysts have built extensive in-house competency in issues related to wholesale power market analysis, evaluation of electric generation assets, distribution, and transmission infrastructure, and regulatory rate design. Ms. Frayer's key areas of expertise include advisory on market design and restructuring, regulated tariff design (cost of service ("COS"), performance-based regulation ("PBR"), long run incremental cost ("LRIC")), development of independent system operator ("ISO") market rules and auction design, renewable energy policy, asset valuation and market analysis, competitive procurement, and financial modeling.

Ms. Frayer's professional experience spans both regulated and deregulated market issues. She has worked on market pricing plans as part of complex commercial negotiations in the

[10] LEI understands that, in certain circumstances, a partial termination of the settlement may occur in which case the new securitization bonds will not be issued, and the Transition Charge will no longer be implemented, but PREPA will still be required to provide equivalent value to the settling bondholders. Assuming such value is generated through rate increases, this would still lead to financial hardship for PREPA.

deregulated energy arena. In recent years, Ms. Frayer has led numerous engagements focusing on strategic power market reforms, including re-design of wholesale markets and deregulation to support private investment. She has been advising clients across the US and Canada on a variety of wholesale market reforms to ensure energy market sustainability, efficient system operations, as well as security and reliability of service. She has also performed extensive utility and electric sector asset valuations and due diligence in conjunction with proposed mergers and acquisitions, divestitures, and project financing. LEI's market price forecasting analytics, under Ms. Frayer's supervision, have supported billions of dollars of transactions and a variety of private sector financings. She has also worked on regulated transmission and distribution rate design issues, including advising on best practices for incentivizing transmission investment and the efficacy of different transmission cost allocation methodologies. Ms. Frayer is currently engaged on several PBR projects, including developing efficiency-driving rates for her clients in the natural gas and electricity industries. Ms. Frayer has presented analysis to numerous state regulators, in addition to testifying before the US Federal Energy Regulatory Commission ("FERC"), as well as other international regulators. Please see Section Exhibit A for Julia Frayer's curriculum vitae.

1.4.2 London Economics International LLC

For over 20 years, LEI has performed extensive consulting and advisory work related to the electricity and infrastructure sectors across North America and globally (including numerous island jurisdictions), advising clients and regulators on regulatory reform, privatization and asset valuations, electricity market design, system planning, and procurement of resources. LEI also conducts rate design reviews and cost allocation studies, along with counseling governments, utilities and regulators on how to design efficient and sustainable tariffs. Furthermore, LEI has engaged with utilities, regulators, and other government bodies in several islands on a wide range of electricity policy topics, including issues relating to the emergence of new technology. Some of LEI's experiences working with island-based electricity utilities or regulators includes the following projects:

- For the Hawaii government, LEI provided a study to assess options for transforming the ownership and regulatory model used to govern its electricity sector. LEI's analysis included a review of long-term operational and financial costs and benefits of electric utility ownership models, regulatory models, and rate design to serve each county of the State of Hawaii. This large, significant initiative provided the government of Hawaii with independent and objective research and analysis to help it scope out the most appropriate course of action in achieving Hawaii's overarching policy goals.

- For the government of Nova Scotia, LEI performed several analyses related to the organization and governance of electricity systems, with an eye towards harnessing best practices from other jurisdictions. LEI reviewed global experience related to electricity sector restricting and liberalization, PBR, and performance monitoring for the generation, transmission, and distribution sectors, as well as analysis of regulatory techniques for mitigating customer and service provider risks. Furthermore, LEI assisted Nova Scotia's Utility and Regulatory Board with setting performance standards with respect to reliability, response to adverse weather conditions, and customer service.

- LEI staff delivered technical assistance to the Haitian Energy Regulatory Agency to empower the newly created regulatory authority (along with other stakeholders) with theoretical knowledge (backed by practical case studies), and best practices. LEI's regulatory building efforts will support Haiti's efforts towards market liberalization and better ratemaking.

- For a power utility in the Caribbean, LEI performed an intensive study of the types of PBR employed by regulators worldwide and the implications for key stakeholders, culminating in workshops for the regulator, utility managers, and government representatives. Key issues covered in LEI's analysis included various forms of PBR, accounting for the unique nature of island systems, impact on employment, and calculation of an appropriate return on equity.

- LEI provided a preliminary valuation of various overseas generation and distribution assets located in the Caribbean (including Curaçao, Grand Bahama, Jamaica, and Trinidad and Tobago) and the Philippines for a private equity firm considering an acquisition. LEI prepared plant by plant summary pro-forma financial models of plant cash flow; regulatory risk assessments; review of major power purchase agreements and other commercial terms of relevance to operations and financing. LEI also prepared a narrative report describing its due diligence and findings. The project also involved the identification of possible purchasers of these assets in the future.

- Over the years LEI has assisted multiple entities in evaluating the acquisition of generation assets being divested from an affiliate of Singapore Power, as part of the liberalization process on the island of Singapore. LEI modeled the Singapore electricity system, considered potential market rules evolution, and the risks and opportunities presented in the Vesting Contracts. LEI also evaluated the economics of new entry and how that would affect existing portfolios of generation and future market outcomes.

- As part of a consortium, LEI was hired by the Singapore National Climate Change Secretariat ("NCCS") to undertake a study on effective carbon prices faced by energy-intensive manufacturing sub-sectors in jurisdictions across Asia, Middle East, Europe, and North America. Specifically, LEI examined carbon policies in select island economies across Asia, Middle East, and North America, including Taiwan and Puerto Rico. The deliverables consisted of a modeling tool to allow the NCCS to compare effective carbon prices across competitor jurisdictions in key manufacturing sectors and thus inform current and future policy decisions regarding the level of Singapore's carbon price and wider climate change policy vis-à-vis key classes of industrial customers in the electricity sector.

- For the Hong Kong government, LEI reviewed the rate base and the permitted rate of return for the power companies in Hong Kong under the Scheme of Control Agreements. This required reviewing the alternatives to using Average Net Fixed Assets as the rate base, examining the assumptions used and methodology to calculate the weighted average cost of capital for the power companies, updating the indicative range for the permitted rate of return, and recommending changes to existing rates by identifying international best practices.

More generally, LEI staff has extensive experience providing a variety of expert witness testimony, both written and oral, before regulatory bodies, administrative law judges, and arbitration panels. A summary of LEI's qualifications can be found in Exhibit B.

2 Summary of the proposed Restructuring Support Agreement

PREPA is a municipal utility owned by the Commonwealth of Puerto Rico and is the only electric utility providing electric power on the island. PREPA is substantially indebted, with its latest audited financial statement reporting $15.6 billion in total liabilities and total assets of $7.9 billion (this financial position is for fiscal year ended June 30, 2017 - before the hurricane damage). The majority of PREPA's liabilities are in the form of debt. According to the August 2018 certified Fiscal Plan ("CFP2018") and reiterated in CFP2019, PREPA had $9.25 billion in outstanding debt as of May 3, 2017, with debt service obligations of $4.5 billion over the subsequent five years.[11]

In July 2017, PREPA had insufficient cashflow to service its debt, and therefore entered a "Title III" restructuring process.[12] Since initiating this process, there have been repeated efforts to settle and restructure PREPA's bond obligations. The most recent such effort is reflected in a new Restructuring Support Agreement ("RSA"), which was reached on May 3, 2019 and subsequently amended as recently as September 9, 2019 ("Definitive RSA").[13] This Report analyzes the consequences of the Definitive RSA on PREPA's operations and its customers.

2.1 Description of the Definitive RSA

The Definitive RSA was entered into by and among: (i) PREPA; (ii) the Puerto Rico Fiscal Agency and Financial Advisory Authority ("AAFAF"); (iii) the Financial Oversight and Management Board for Puerto Rico ("FOMB"); and (iv) members of the Ad Hoc Group of PREPA Bondholders, Assured Guaranty Corp. and Assured Guaranty Municipal Corp. (together, "Assured"), National Public Finance Guarantee Corporation ("National"), and Syncora Guarantee Inc. ("Syncora").

At the time of its Title III petition date, PREPA's outstanding bonds included approximately $6 billion of uninsured bonds and $2.25 billion of bonds that were guaranteed by monoline insurance companies.[14] The bondholders that are part of the Definitive RSA will exchange their current bonds for new securitized bonds, assuming the settlement is fully consummated. There will be two tranches of the new securitized bonds: Tranche A and Tranche B. Tranche A will have a notional maturity of 40 years, but may be paid out earlier depending on electricity

[11] CFP2018, slide 37; CFP2019, slide 103.

[12] Title III refers to the section of the Puerto Rico Oversight, Management, and Economic Stability Act ("PROMESA") that covers court-supervised restructurings of United States territories and their covered instrumentalities (such as PREPA). A territory that files for protection under Title III is allowed to continue to operate and provide services uninterrupted. An "automatic stay" is imposed that prevents creditors from taking actions to collect money and debts owed by the debtors. The automatic stay provides the debtors with an opportunity to negotiate with creditors.

[13] AP News (Press Release). "Ad Hoc Group of PREPA Bondholders Announces Agreement with the Oversight Board, AAFAF, PREPA and Other Significant PREPA Bondholders." May 3, 2019.

[14] US District Court for the District of Puerto Rico. Joint Motion of Puerto Rico Electric Power Authority and AAFAF Pursuant to Bankruptcy Code Sections 362, 502, 922, and 928, and Bankruptcy Rules 3012 (A)(1) AND 9019 For Order Approving Settlements Embodied in the Restructuring Support Agreement and Tolling Certain Limitations Periods. (Case No. 17-BK-3283-LTS), (referred to herein as the "9019 Motion"). Page 3.

consumption trends and load growth prospects.[15] However, if the principal is not paid off before the end of this 40 year term, then Tranche A's term will be extended until all interest and principal amounts for Tranche A bonds are paid off. Tranche B will have a maximum term of 47 years from effective date of the Definitive RSA and would not begin payment until all Tranche A bonds are paid in full.[16]

2.2 Transition Charge will recover costs of bondholder legacy debt from PREPA consumers

Pursuant to the Definitive RSA, a fixed and non-bypassable rate adder, known as the Transition Charge, will be part of the final electricity rates. The Transition Charge will be collected from all PREPA customers. The Transition Charge will secure the payment amounts for the new Securitization Bonds, specifically the Tranche A bonds and Tranche B bonds.[17] The Transition Charge will begin with the Title III plan effective date, currently targeted for FY 2021. Given the maturity dates of the Securitization Bonds, the Transition Charge will be added on top of electricity rates for over four decades (nominally, 47 years).[18]

Figure 1 on the next page summarizes the levels of Transition Charge that would be added to electricity bills for all customers, starting with 2.768 cents/kWh (in FY 2021) and growing to 4.552 cents/kWh (in FY 2043).[19] The Transition Charge will be capped at 4.552 cents/kWh for all remaining years of the term.[20] Although it is not shown in the figure, the Transition Charge is likely to continue beyond FY 2044 (which would only be the 24th year of the term for Tranche A bonds). The final year of the maximum term of the Tranche B bonds would be FY 2067.

The Definitive RSA also anticipates a Settlement Charge of 1 cent/kWh, applied to all PREPA customers, for the benefit of bondholders that have signed on to the Definitive RSA.[21] This Settlement Charge would apply as soon as the court approves the settlement, and continue until the issuance of new securitization bonds or April 2021, when the Increased Settlement Charges would be implemented.

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[15] Financial Oversight and Management Board for Puerto Rico ("FOMB"). Unanimous Written Consent Approving Execution of Definitive Restructuring Support Agreement of Puerto Rico Electric Power Authority. Exhibit C: Recovery Plan Term Sheet. May 3, 2019.

[16] US District Court for the District of Puerto Rico. Joint Motion of Puerto Rico Electric Power Authority and AAFAF Pursuant to Bankruptcy Code Sections 362, 502, 922, and 928, and Bankruptcy Rules 3012 (A)(1) AND 9019 For Order Approving Settlements Embodied in the Restructuring Support Agreement and Tolling Certain Limitations Periods. (Case No. 17-BK-3283-LTS), ("9019 Motion"). Page 8.

[17] Ibid. Page 3.

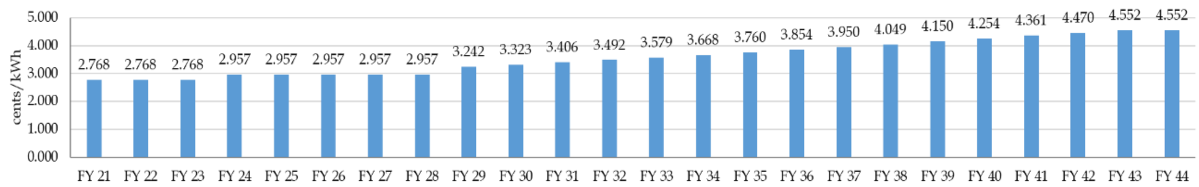
[18] As noted above, it is possible that a partial termination of the settlement may occur in which case the new securitization bonds will not be issued, and the Transition Charge will no longer be implemented, but PREPA will still be required to provide equivalent value to the settling bondholders.

[19] Ibid. Page 20.

[20] Ibid. Page 99.

[21] Ibid. Page 27.

Figure 1. Summary of the Transition Charge, FY 2021 – FY 2044



Source: Financial Oversight and Management Board for Puerto Rico ("FOMB"). *Unanimous Written Consent Approving Execution of Definitive Restructuring Support Agreement of Puerto Rico Electric Power Authority*. Exhibit C: Recovery Plan Term Sheet. May 3, 2019.

2.3 Transition Charge will be fixed and non-bypassable

The Definitive RSA anticipates setting the level of the Transition Charge before the plan effective date.[22] After it is set, the Transition Charge will not vary with electricity consumption trends. However, the amount of funds collected through the Transition Charge will depend on future electricity sales volume. The intent of the Definitive RSA is that all PREPA customers will pay the Transition Charge, including those that may have behind the meter generation (self-supply) or simply rely on only a fraction of the services that PREPA provides (for example, for customers connecting only for backup power). An entity consuming electricity in Puerto Rico can avoid the Transition Charge only if it completely disconnects from the PREPA system. As noted on Schedule I-A Demand Protection Term Sheet of the Definitive RSA:

> *the "Transition Charges are non-bypassable charges, the payment of which shall be obligatory. Transition Charges shall be assessed on all customers, regardless of the date as of which they become customers …"*
>
> *"customers shall not be permitted to evade the imposition of Transition Charges or reduce their responsibility for Transition Charges by disconnecting and subsequently reconnecting to the system."*[23]

Customers with either existing or new behind-the-meter generation ("BTMG") will not be able to avoid the Transition Charge, as they will be assessed in proportion to their actual or implied net consumption before the imposition of the Transition Charge.[24]

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[22] The calculation of the Transition Charge is subject to a number of assumptions, including but not limited to: (a) 100% of the bonds are exchanged, (b) the transaction closes on June 30, 2020, and (c) the Settlement Charge is paid as provided. In addition, the Transition Charge could be adjusted prior to the effective date to account for when the effective date occurs, certain cash payments to bond holders, and as needed to ensure a match with projected actual collections (e.g., so the final Transition Charge may reflect updates to PREPA's load forecasts). *See* 9019 Motion, page 98.

[23] US District Court For the District of Puerto Rico. Joint Motion of Puerto Rico Electric Power Authority and AAFAF Pursuant to Bankruptcy Code Sections 362, 502, 922, and 928, and Bankruptcy Rules 3012 (A)(1) AND 9019 For Order Approving Settlements Embodied in the Restructuring Support Agreement and Tolling Certain Limitations Periods. (Case No. 17-BK-3283-LTS). I-A-3.

[24] Ibid. Page I-A-4.

3 Overview of electricity rate design

Cost of service is the basic premise used in setting rates of regulated utilities worldwide. As the wording suggests, rates should remunerate the utility for its total costs of providing services. Rates based on this overarching premise would be consistent with the beneficiary pays principle, and ensure efficient consumption of the service. Total costs of services include operating expenses, taxes (to the extent that the utility must pay them), and recovery of capital-related costs over time. Capital-related costs may include depreciation expenses, financing costs, and a return on equity, as seen in the graphic below. The philosophy of full cost of service applies equally to to publily-owned and privately-owned utilities. In the case of PREPA, and especially in recent years, rates have not achieved full cost of service recovery.

Figure 2. Costs of services - components of a revenue requirement

Operating costs + Tax expense + Equity-financed portion of Asset Base x Allowed return on equity + Depreciation expense (return on invested capital) + Interest expense (financing costs)

In April 2019, Puerto Rico passed new legislation ("Act 17-2019") geared at modernizing the island's electricity regulation. The legislation included language specifying that rates must provide for full cost recovery.[25] As recognized in Act 17-2019, there has been considerable innovation in rate design in the last 30 years, and the legislation explicitly allows for more innovative rate design, for example, decoupling,[26] PBR,[27] and time of use rates.[28] However, all rate design permutations are still based on the cornerstone of utility regulation requiring recovery of all commercially reasonable costs to supply electricity, including a return on and of capital.[29] Even as PREPA transitions to more private sector involvement and harnesses the benefits of competition, the principles of full cost recovery must be adhered to: customers should pay for services provided by PREPA in order to allow for a fiscally sound and

[25] Act No. 17-2019, Section 5 (e) states that the public policy of Puerto Rico is "[t]o promote and oversee that prices are based on the actual cost of the service provided, efficiency standards, or any other parameters recognized by the electric power service industry."

[26] Decoupling is a rate adjustment mechanism that breaks the link between the amount of energy a utility sells and the revenue it collects to recover the fixed costs of providing service to customers. Source: NREL. *Decoupling Policies: Options to Encourage Energy Efficiency Policies for Utilities*. <https://www.nrel.gov/docs/fy10osti/46606.pdf>

[27] Please see Appendix B for a short description of PBR.

[28] *See* Act No. 17-2019, Section 6.25B. – Performance Based Incentives and Penalty Mechanisms.

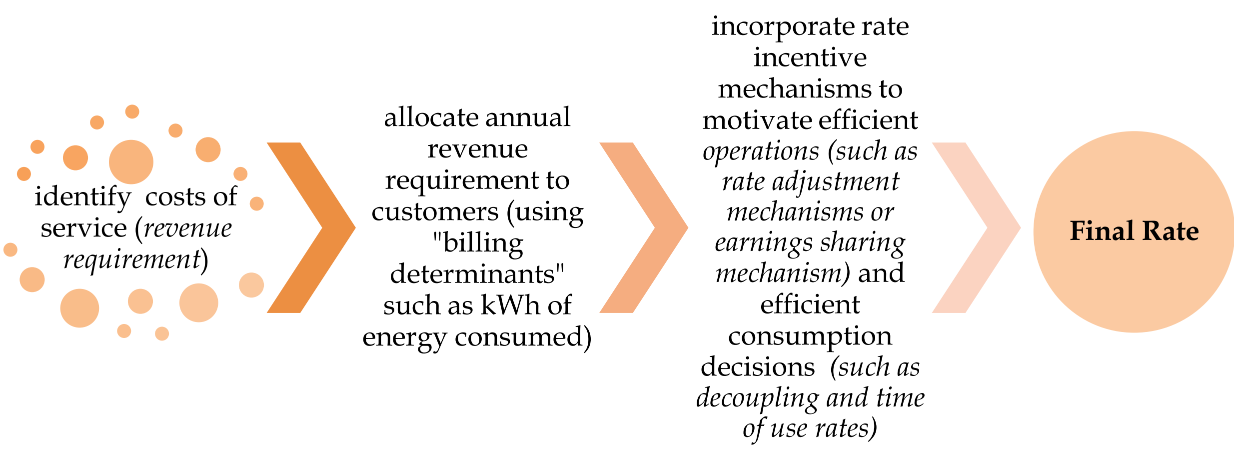
[29] For a public utility, the return on and off capital may be embodied in the financing costs (the repayment of principal and interest expense). However, for an investor-owned utility or for service providers providing services to a public utility, there will need to be return on and off equity, in addition to debt repayment. For more information, *see* Bonbright, Danielson and David Kamerschen. *Principles of Public Utility Rates*. Public Utility Reports Inc. Arlington, VA. 1988; Bonbright, Danielson. *Principles of Public Utility Rates*, Public Utility Reports Inc. Arlington, VA. 1961. Page 290-94; Weston, Fredrick. "Principles of Rate Design." 1999. <www.raponline.org>; and Woolf, Tim and Julie Michals. "Performance-Based Ratemaking: Opportunities and Risks in a Competitive Electricity Industry." *The Electricity Journal* 8.8 (October 1995).

sustainable enterprise.[30] As such PREPA's future rates must cover all costs incurred in generating, transmitting, and distributing the electricity.

3.1 Rate design concepts

Rate design must begin with a comprehensive understanding of the costs of service, otherwise known as a revenue requirement, as shown in the figure below. The costs are then allocated to customers based on their contribution to the overall costs. In order to ensure efficient consumption decisions, customers should be responsible for paying for the total costs of services. Typically, a utility will pick a billing determinant in order to allocate costs of service. Average rates are set based on the revenue requirement divided by the volume of electricity consumed by all customers, as measured by kilowatt hours ('kWh").[31] Finally, incentive-enhancing rate design mechanisms may be applied to motivate the utility to seek out efficiencies in operations and motivate consumers to be efficient in their consumption decisions, e.g., conserve energy to more effectively make use of the utility's assets.

Figure 3. Key steps in rate design methodology



3.2 Basic components of the revenue requirement

There are both fixed and variable costs of electric utility operations. Fixed costs include capital-related costs (e.g., interest expense, return on equity and depreciation expense shown in Figure 2 above), labor costs, and certain operating and maintenance ("O&M") expenses,[32] which are

[30] Theft of electricity is a subset of electricity that is consumed (but not paid for) and is accounted for in the cost of service calculation.

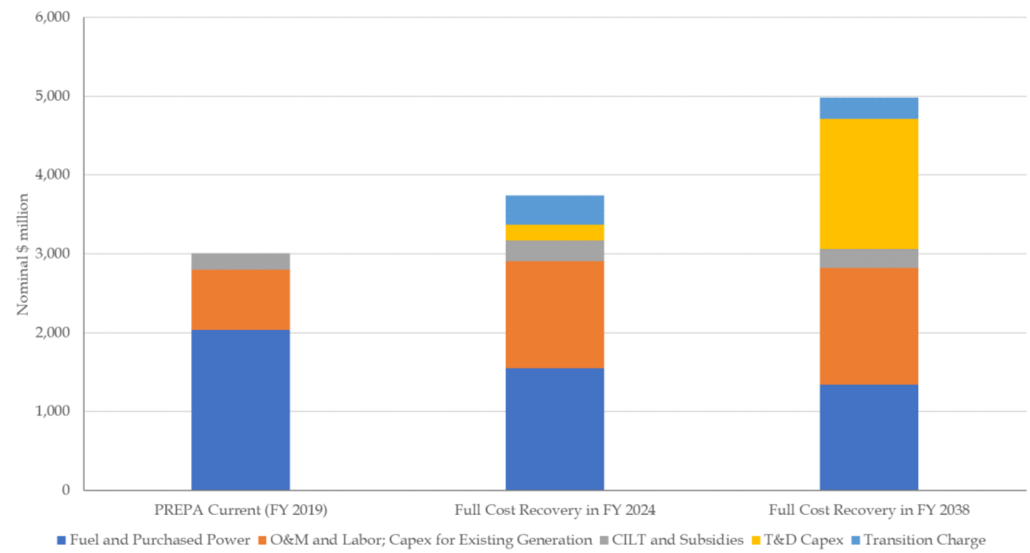
[31] In recent years there has been a push to move to fixed billable units that are not volume-dependent, such as per customer charges or demand charges. This has been accomplished through revenue decoupling, lost revenue adjustment mechanisms, residential demand charges and minimum bill charge features. In addition, there is precedent in other industries, such as telecommunications, where the variable costs are minimal and all costs are effectively passed through as a fixed charge. The form of allocation to customers does not, however, change the primary premise that all costs of service need to be paid for by customers.

[32] Labor and O&M expenses are part of the "Operating costs" category in Figure 2 above.

generally invariant to generation and consumption levels in the short-term. Variable costs typically include fuel costs and certain types of O&M expenses (referred to as variable O&M).[33] PREPA's current rates are intended to cover all variable and fixed O&M costs and fuel costs, as well as notional tax payments (known as Contributions In Lieu of Taxes, or "CILT"). Some of PREPA's financing costs were budgeted into rates, but far below the full repayment amount. In addition, PREPA's operating cost budgeting processes have been repeatedly questioned as sub-standard. The independent investigator for the FOMB identified that PREPA's rates were historically "high and, yet, insufficient to cover operational expenses and capital improvement projects," and that this lack of full cost recovery was a leading contributor to Puerto Rico's financial crisis.[34] "To compensate for the suppressed base rate, PREPA became dependent on short-term liquidity injections from GDB [i.e., Government Development Bank of Puerto Rico], with its principal means of repayment being the issuance of bonds."[35] Indeed, even PREPA's own advisor, Filsinger Energy, appears to have recently probed the accuracy and validity of PREPA's budgets.[36]

The Transition Charge, if the Definitive RSA is approved, can be thought of as a capital-related cost because it provides payment for legacy debt, which was essentially incurred to pay for the use of PREPA's generation and T&D assets. As additional investment is incurred in the future, capital-related costs in the revenue requirement will grow, as seen in the figure below.

Figure 4. Illustration of the components of PREPA's revenue requirement



Source: LEI modeling.

[33] Fuel and Variable O&M expenses are also part of "Operating costs" shown in Figure 2.

[34] Kobre & Kim LLP. *Final Investigative Report*. The Financial Oversight & Management Board of Puerto Rico. August 20, 2018. Pg. 4-5. <https://assets.documentcloud.org/documents/4777926/FOMB-Final-Investigative-Report-Kobre-amp-Kim.pdf>

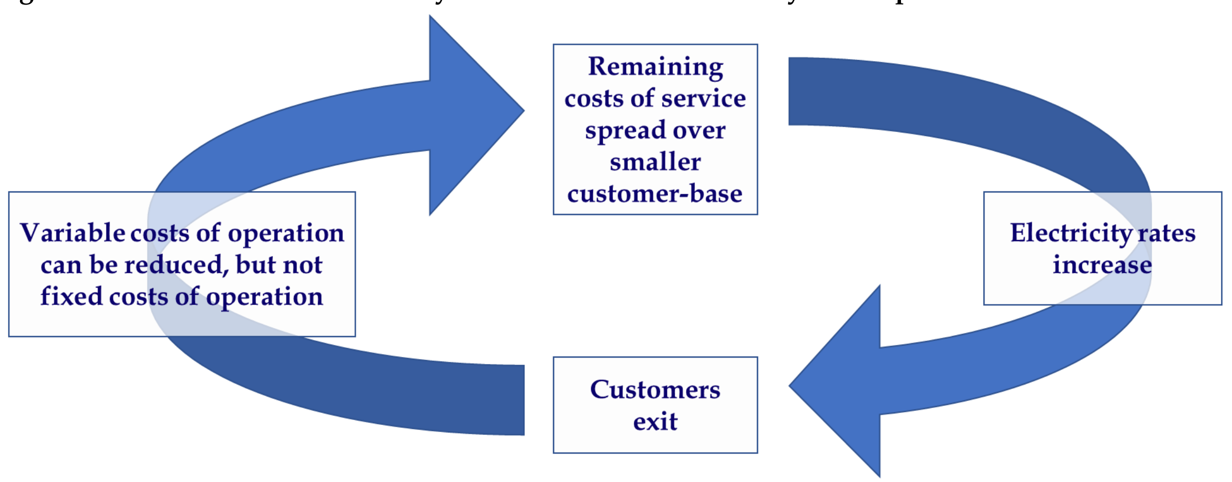
[35] Ibid.

[36] Scott Davis of Filsinger Energy, email dated July 25, 2019 with subject line "RSA Headroom Discussion". The email also contained a PowerPoint entitled "Revenue Allocation Overview: FY's 2019 & 2020," dated June 30, 2019, *see* page 9.

3.3 Challenges to keep in mind

Electric utility operations are typically heavily weighted towards fixed costs because of the industry's capital-intensive nature. However, as noted above, fuel purchases are a form of variable costs. As PREPA transitions to increased renewable generation, variable costs will decline. This has profound implications for thinking about future rates in the face of changing levels of electricity consumed by customers. Given that the majority of PREPA's costs are fixed, as total volume of electricity (and total number of customers) declines, it may not be possible to reduce the revenue requirement proportionally to demand.[37] In such circumstances, the rates payable by customers will have to increase. Rising rates, coupled with falling costs for solar photovoltaic ("PV") generation and other distributed generation technologies, may lead to even more customers opting to acquire on site ("behind the fence" or "behind the meter") generation, as discussed in Section 6.3 of this Report. This can create the potential for a vicious rate cycle: the fewer customers there are, the higher that rates must be to ensure full cost recovery. At the same time, higher rates will motivate customers to seek out ways to reduce their consumption, or, in the extreme, leave the utility system altogether. In the regulatory field for electric utilities, stakeholders are referring to this challenging situation as the "utility death spiral."[38, 39]

Figure 5. Illustration of the vicious cycle that can lead to the utility death spiral



[37] Only with time, when assets are retired, will costs go down. However, retiring assets that are not fully depreciated may create write-offs and stranded costs. Such actions have their own set of complex and potentially negative financial ramifications.

[38] Many industry stakeholders point back to the seminal Edison Electric Institute ("EEI") paper in 2013, authored by financial expert Peter Kind and entitled "Disruptive Challenges," as first identifying the theoretical threat posed by technological advances to the traditional utility business model. Peter Kind theorized that the traditional utility business model may not sustain wide adoption of DER solutions, resulting in a "utility death spiral." Although no utility has yet succumbed to such a death spiral, there are cautionary tales from other industries. Moreover, regulators across the world have shown a clear willingness to thoughtfully consider the consequences of policies and other actions that could create such a tailspin.

[39] Andrew Wolfe, consultant to the FOMB, also speaks of serious consequences of a "downward economic spiral" for Puerto Rico, that may be precipitated if PREPA's rates rise too quickly. In his Declaration from July 31, 2017, Mr. Wolfe explains that rising electricity rate burdens would result in lower electricity consumption and push PREPA into another fiscal crisis. See paragraph 10 (page 7), paragraph 12 (page 7) and paragraph 45 (page 17).

4 Critical review of PREPA's recent certified Fiscal Plans

The viability of the proposed settlement (e.g., the Definitive RSA), and whether it creates an opportunity for other creditors to also recoup their debts, rests squarely on whether consumers can afford to pay for electricity service, inclusive of the Transition Charge. There are multiple dimensions to such a question, including: analysis of the challenges to realizing rate reductions that PREPA may face; whether and how consumers will react to the higher electricity rates (which will be discussed further in Section 5); what a pragmatic demand forecast will look like (which will be focused on in Section 6); and what LEI's forecasted rates look like and the implications of the Transition Charge (see Section 7). However, it is best to begin with a basic understanding of PREPA's cost of service today along with PREPA's rate expectations for the future.

4.1 PREPA's current rates are not providing for full cost of service recovery

Pursuant to the latest Rate Order, current base rates are not reflective of the capital-related components in costs of service (the Rate Order from 2017 approved only $440 million for debt service and coverage, which is substantially less than the estimated annual debt service of $657 million disclosed in CFP2018).[40] Furthermore, as is evident in the audited financial statements and PREPA's certified Fiscal Plans, current rates do not include any consideration of a return on previously invested capital.[41] As stated in the regulator's *Final Resolution and Order* (dated January 10, 2017), PREPA's rates were not based on actual needs but limited by internal ceilings that were rooted in political concerns about rate increases.[42]

If PREPA is to move towards a sustainable business model, it will need to achieve full cost of service recovery from customers. The rebuild of the transmission and distribution system is being funded primarily by Federal emergency relief funds, similar to the concept of contributed capital. As such, rates do not necessarily need to reflect a return on and of this contributed capital. However, additional investments in infrastructure will be needed to support the Transformation and costs of those capital investments will need to be recovered from PREPA's customers. In addition, third-party operators, like the anticipated T&D operator (or "concessionaire"), will need to be remunerated for their services. Similarly, if PREPA were to divest its existing generation, then the new owners would also require a commercially reasonable return on and off the capital they expend on the purchase and ongoing investment to maintain the operable performance of the assets. As a result, the rates will need to increase to cover these additional costs of service.

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[40] PREC. Final Resolution and Order. *Puerto Rico Electric Power Authority Rate Review*. January 10, 2017. Page 4. *See also* CFP2018, slide 27. This estimated debt service is based on based on term out of all long-term financial liabilities at a 5% interest rate over 25 years.

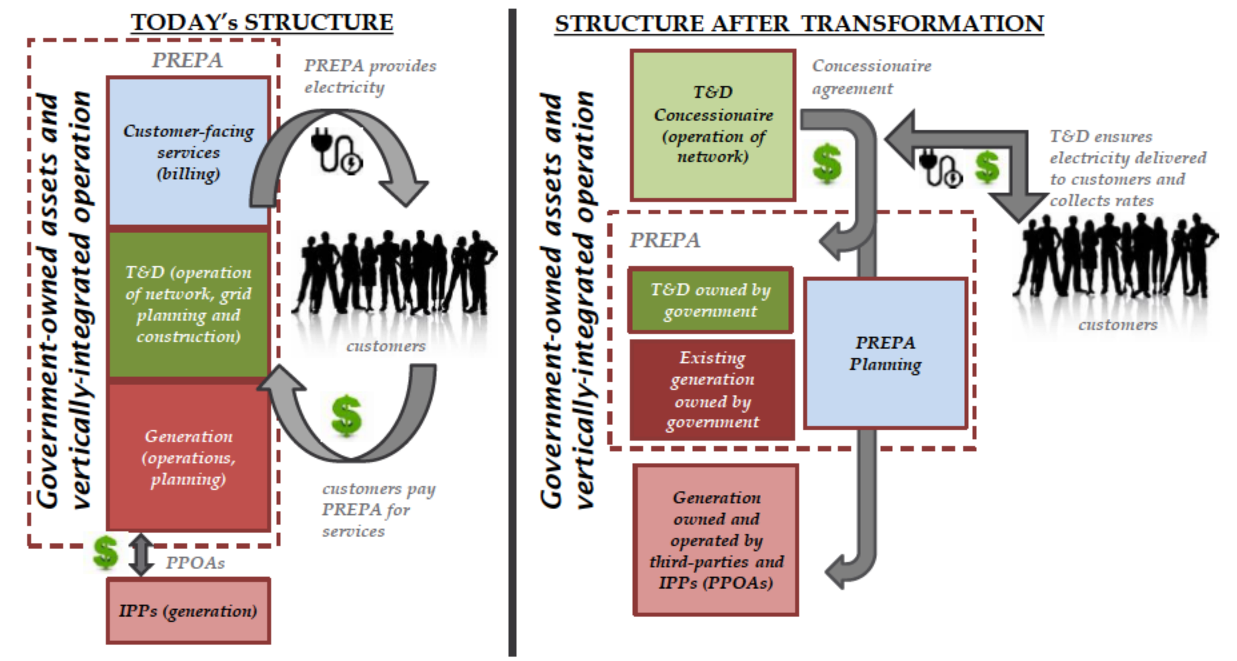
[41] Regulators establish a reasonable return on assets, which is also commonly captured in the allowed return on equity ("allowed ROE"). The allowed ROE is applied to a utility's regulatory asset base or net book value. A utility's regulatory asset base will increase from the year prior with capital expenditures, and it will decrease from the year prior because of depreciation expense and retirements.

[42] PREC. Final Resolution and Order. *Puerto Rico Electric Power Authority Rate Review*. January 10, 2017. Page 3-4.

4.2 PREPA's forecast of rates are based on several unrealistic assumptions

Annually, PREPA prepares short-term forecasts of rates in its annual budget and fiscal plan. LEI has reviewed PREPA's CFP2018 and the more recently issued CFP2019.[43, 44] PREPA's short-term strategic plan assumes that PREPA will be able to complete a major reorganization of its business, as highlighted in Figure 6 below.

Figure 6. Structure of the electricity sector in Puerto Rico: today versus post-Transformation



Note: Graphic based on illustration in CFP2019, slide 18 and the concept of the "Servicer" in the Definitive RSA.

The reorganization, and associated transactions, are not unprecedented. Many jurisdictions around the world have successfully privatized their electricity utility sector. The unrealistic aspects of PREPA's strategic plan however relate to the implementation details (for example, timing of bringing on new private operators and getting new facilities commercialized) and accounting of the costs associated with private-sector operations, including the following:

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[43] There are a few differences between the CFP2018 and CFP2019: (i)CFP2019 projected rates exhibit an increasing pattern over time, while the Aspirational scenario[43] in CFP2018 had a decreasing trend (see Figure 7 on page 28); (ii) CFP2019 includes the costs of meeting pension liabilities, which were not addressed in CFP2018; and (iii)in CFP2019, PREPA rearranged some of its operating costs to showcase the goal of unbundling the T&D operations from the generation operations (and privatizing operations of the existing generation assets). However, CFP 2019 continues to overlook the fact that both a generation operator and T&D concessionaire will require a management fee or commercially reasonable profit margin to take on the obligations of operations.

[44] In the critical review of PREPA's rate expectations, LEI focused on CFP2019, as it is the latest release of PREPA's fiscal plan. FY 2019 estimates and FY 2020 projections from CFP2019 were used as a starting point in LEI's forecast of rates in Section 7.

- PREPA continues to assume that a T&D concessionaire would take control of the system next year, despite the fact that PREPA's CEO has repeatedly suggested that obstacles have arisen and delays have occurred in the concessionaire selection process.[45] Notably, a process for soliciting for an independent operator (or operators) for PREPA's existing generation assets has not yet begun.

- CFP2019 continues to ignore the basic commercial premise that private-sector operators of the T&D system and the generation assets would require a reasonable profit margin or "management fee" for their services. CFP2019 discloses that such costs were not incorporated into the forecast of costs of service and rates.[46]

- In the CFP2019, PREPA presented a five-year outlook for costs of service, based on the IRP 2019 filed with Puerto Rico Energy Bureau ("PREB") (dated June 7, 2019), and also reflecting some updated "macroeconomic" information (which presumably was compiled after IRP 2019 was prepared).[47] Given its reliance on IRP 2019, PREPA assumes aggressive and unrealistic timing in the construction of various new generation infrastructure. For example, CFP2019 appears to assume operation of 1,380 MW of new solar generation capacity and 920 MW of new battery generation capacity by 2022,[48] even though no solar RFPs or battery RFPs have been completed yet. If the investments in renewables is more costly and takes more time, PREPA will need to continue to rely more extensively on energy produced by its fossil fuel-fired generation, which will raise costs to consumers. On top of this, CFP2019 also acknowledges that the generation projections for its fossil fuel-fired assets is unrealistically "perfect" and therefore underestimates the real costs of fuel purchases to meet electricity demand on the island.[49]

- PREPA continues to assume that the Federal government will provide 90% of the funding for necessary T&D-related capital investment over the next ten years. Under such circumstances, customers would be spared the rate increases that would otherwise occur to reflect these capital-related costs. There is no certainty that the Federal government will provide such funding. [redacted]

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[45] For example, Mr. Ortiz argued as recently as August 13, 2019 that the concessionaire arrangements are being held up by disbursements from FEMA. *See* https://caribbeanbusiness.com/puerto-rico-utility-director-wants-fema-to-repair-grid-so-it-can-be-privatized/. In addition, Mr. Ortiz, as part of his written statement before the House Committee on Natural Resources, in the *Hearing on the Rebuilding and Privatization of the Puerto Rico Electric Power Authority* on April 9, 2019, anticipated that "qualified respondents" would be "identified in mid-August", but there has been no such public announcement by either P3 Authority or PREPA as of mid-September 2019.

[46] The profit margin (e.g., management fee) for an independent operator was not included in the build-up of expenses in CFP2019. *See* CFP2019. Slide 71 and 73.

[47] CFP2019, slide 8 states that one of the overarching goals of this Fiscal Plan was to use the most up-to-date financial projections, including "recent macroeconomic data".

[48] CFP 2019 notes that it has relied in IRP 2019 for its resource mix (slide 21). See pages 20-21 of IRP 2019.

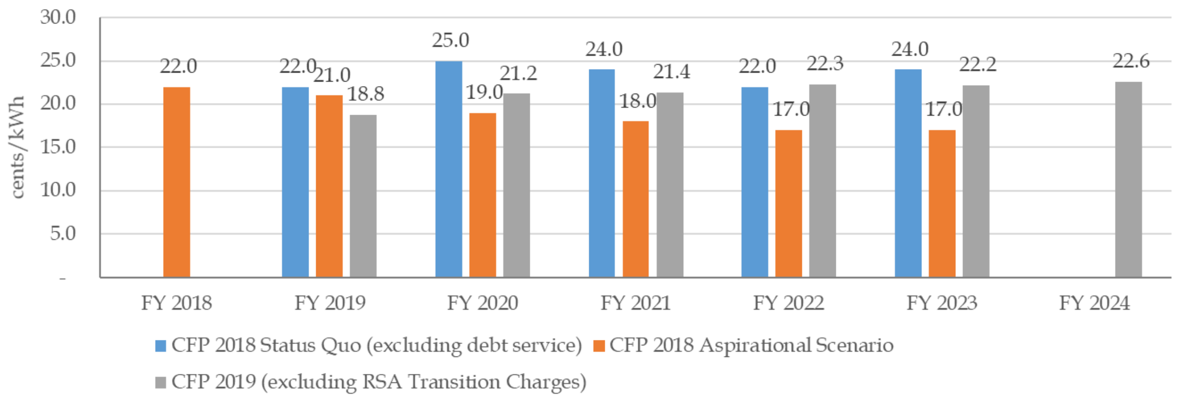
[49] CFP2019. Slide 66.

[redacted].[50] If the Federal funding is not available, CFP2019 discloses that rates would be higher – customers would be responsible for an additional $241 million of T&D capital related costs per year (or 0.7 cents/kWh to 2.8 cents/kWh of rate impact from FY 2020 to FY 2024).[51]

4.2.1 With CFP2019, PREPA shows various uncertainties in its analysis

CFP2018 presented two scenarios: a "Status Quo" scenario and a very optimistic sensitivity, which PREPA called the "Aspirational" scenario, reflecting targets that "can be potentially achieved, but only after securing substantial resources for T&D and Generation improvements before and after FY[20]23".[52] CFP2019 presents only one outlook. As shown in the figure below, the projected rates (excluding the Transition Charge, cents/kWh) in CFP2019 are higher than the Aspirational scenario in CFP2018, but also lower than the Status Quo scenario in CFP2018.[53]

Figure 7. Projected average rates in CFP2018 and CFP2019



Source: CFP2018, slides 38 and 43 and CFP2019, slide 62.

The discontinuation of presentation of the "Aspirational" scenario is a notable difference between PREPA's CFP2018 and CFP2019, and indirectly sheds light on some of the unrealistic

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[50] P3 Authority. "Operation and Maintenance Agreement", Section 4.5 (h). Source: PRP3_OCUC_00013514

[51] CFP2019. Slide 67. Calculated using the c/kWh Federal Funding Risk multiplied by the MWh forecasted demand, and averaged from FY2020 to FY 2024.

[52] CFP2018. Slide 78.

[53] CFP2018 presented a bifurcated view of future rates: providing a status quo picture as well as an "aspirational" view. In addition to the various optimistic assumptions and uncertainties that have been mentioned above for CFP2019, CFP2018 had overly ambitious assumptions about the future costs of operation. For example, CFP2018 assumed substantial savings in fuel costs over historic level, which were conditioned on assumptions on projected fuel prices and operations of new renewables. Even if fuel contracts are to be negotiated, they will remain variable and unknown (all fuel oil prices will be based on market price at time of delivery, as noted by Mr. Vasquez, the Executive Director and CEO of PREPA in his written statement before the House Committee on Natural Resources Hearing on the Rebuilding an Privatization of PREPA, April 9, 2019). In addition, CFP2018 had projected an ambitious timeline for certain units' conversion to LNG. Operation of the San Juan facilities on LNG have been delayed over the original target date in CFP2018. CFP2018 also had unrealistic goals for start of operation of new renewable generation. As of the date of CPF2019, procurements for new renewable resources are still ongoing; construction of new solar plants has not begun.

assumptions being made by PREPA. In fact, PREPA acknowledges the uncertainties embedded in its forecast in CFP2019 by enumerating several factors which could make future rates much higher:

- if the term of the pension liabilities is not restructured to reflect a longer time period, rates could be in excess of 3.5 cents/kWh higher in FY 2034;[54]
- if Federal funding is not available for necessary T&D investments, customers will need to finance such investment at an additional cost of 3 cents/kWh (for the first $8 billion)[55] and approximately an additional 10 cents/kWh cost for the next $8 billion;[56]
- inefficient dispatch of generation could raise rates by 1.08 cents/kWh to 1.28 cents/kWh a year;[57] and
- if PPA prices are not as attractive as suggested in IRP 2019, electricity rates will need to rise by 0.28 cents/kWh to 0.97 cents/kWh a year.[58]

CFP2019 also does not acknowledge the implications of the demand assumptions, but that too can create a significant impact on rates (as discussed further below). Finally, CFP2019 continues to present only a five-year outlook of rates, although PREPA management is planning over a longer term, i.e. the IRP focuses on 20 years. More generally, PREPA has not been transparent about the full extent of T&D investment required in the longer term to achieve both system resilience and its ambitious renewable generation goals.[59] In order to assess the reasonableness of a 47-year Transition Charge in the Definitive RSA, and whether there is additional value for remunerating other creditors, a longer term assessment of rates is necessary.

4.2.2 Shortcomings of PREPA's demand forecast

The most problematic element of PREPA's demand forecast is that it does not factor in the role that increasing rates will have on impacting demand. While most utilities do not have to incorporate the impact of rate changes on demand as part of their demand forecast process, the situation in Puerto Rico is different for two crucial reasons. First, the Definitive RSA and strategic planning that is currently occurring to anchor PREPA's future necessitates long term decision-making. Second, due to economic challenges in Puerto Rico, the island has been suffering from de-population and declining electricity load over the last decade. Given the

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[54] CFP2019. Slide 87.

[55] CFP2019. Slide 67.

[56] CFP2019. Slide 118. The rate impact on next $8 billion will be larger (higher cent/kWh) as the amount of load in FY2025-FY2029 is projected to be lower than for the FY2020-2024 time-period.

[57] CFP2019. Slide 66.

[58] CFP2019. Slide 66.

[59] In his written statement before the Committee of Natural Resource US House of Representative on April 9, 2019, Mr. Ortiz, CEO of PREPA, has suggested that PREPA is working with COR3 and the Puerto Rico Public-Private Partnerships ("P3") Authority to develop the Energy Grid Modernization Plan, but that Plan has not been released publicly. The 10-year T&D capital investment budget revealed in CFP2019 is not sufficient in laying out the longer term investment needs of PREPA.

nature of utility rate setting and the intrinsic role that total load has in calculating rates, it is imperative that demand forecasts in Puerto Rico be conducted on a holistic basis and reflect the impact that critical business decisions and financial policies will have on the costs of service, and how those costs will drive overall consumer behavior and ultimately the volume of electricity over which final rates will be calculated.

Although CFP2019's load forecast is 6.1% higher than the load forecast in the Reference Case in IRP 2019 for FY2019 to FY2023,[60] it appears to be generally based on the same methodology as employed in the IRP 2019. CFP2019 appears to have leveraged updated information on post-storm sales and Gross National Product ("GNP") statistics from the FOMB. The demand forecast methodology in IRP 2019 is based on typical methods: Siemens used population, GNP,[61] cooling degree days ("CDD"), and the monthly dummy variables as explanatory variables in an econometric model to develop the load forecast by customer class for the future. Siemens acknowledges that it did not directly incorporate the resulting costs of service (e.g., customer rates) into its demand forecast: "industrial rates… were found not to have a strong historic correlation to demand and explanatory power."[62] However, numerous studies on electric demand price elasticity have identified a statistically significant long-run negative correlation between electricity demand and rates.[63] Furthermore, higher electricity rates would increase the cost of doing business, and some firms would choose to produce less or move their operations, as implied in earlier testimony by an expert for the FOMB.[64] Therefore, an increase in the electricity rate would lead to lower economic activity in some sectors of the economy in Puerto Rico. PREPA's load forecast does not have this relationship between electricity load and electricity rates, nor any feedback to economic activity trends (such as GNP). This leads to an overestimation of GNP levels in future years, and an overly optimistic electricity demand forecast.

In addition, higher electricity rates under a deteriorating economic condition could lead to a higher level of electricity theft, or "non-technical losses" in the IRP and CFP2019, as some households that cannot afford to pay increasing electric utility bills would be more likely to

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[60] *See* IRP2019 Exhibit 3-34, Sales Forecast Scenario after EE and Customer Generation

[61] Gross domestic product ("GDP") is the value of a nation's finished domestic goods and services during a specific time period. The gross national product ("GNP") is the value of all finished goods and services owned by a country's residents over a period of time. Both are measures of economic activity. GNP is similar to GDP but adjusted for inflows of income earned by nationals working abroad and outflows of income earned by non-nationals. Puerto Rico's GNP is much lower than GDP because of the foreign direct investment and the resulting profits that are repatriated to other jurisdictions. FOMB has focused on GNP statistics for assessing Puerto Rico's fiscal condition. Therefore, in this Report, LEI relies on GNP statistics.

[62] Siemens. Puerto Rico Integrated Resource Plan 2018-2019: Prepared for Puerto Rico Electric Power Authority. Issued June 7, 2019., Report Number: RPT-015-19. ("IRP 2019"). Page 51, Section 3.1.3.

[63] *See* Burke, Paul J. *The price elasticity of electricity demand in the United States: A three-dimensional analysis*. August 2017; Paul, Anthony, Erica Myers, and Karen Palmer. *A Partial Adjustment Model of US Electricity Demand by Region, Season, and Sector*. 2009; Neenan, Bernard and Jiyong Eom. *Price Elasticity of Demand for Electricity: A Primer and Synthesis*. 2009; Bernstein, Mark A., James Griffin. *Regional Differences in the Price-Elasticity of Demand for Energy*. 2005.

[64] Case 17-04780-LTS Doc#149-2 Filed 07/31/17. Exhibit B Wolfe Declaration. Declaration of Andrew Wolfe in Support of Opposition of the Financial Oversight and Management Board for Puerto Rico to the Motion of the Ad Hoc Group of PREPA Bondholders, National Public Finance Guaranty Municipal Corp., Assured Guaranty Corp., Assure Guaranty Municipal Corp., and Syncora Guarantee Inc. for Relief From the Automatic Stay to Allow Movants to Enforce Their Statutory Right to have a Receiver Appointed. Page 6-7.

resort to illegal connections. The IRP 2019 forecast of non-technical loss has the same (negative) growth rate as the total electricity sales forecast,[65] indicating that the non-technical losses are only driven by the level of demand. Economic studies have shown that other factors, such as change in household income and level of electricity rates relative to household income, also impact the level of non-technical losses.

In summary, LEI believes that CFP2019's demand forecast is too static and does not take into account how electricity demand would be impacted by future rate changes. The demand forecast in IRP 2019 also lacks a feedback loop between electricity rates (and electricity consumption) and economic activity (e.g., GDP). If these factors are incorporated into the demand of forecast, the forecasted annual electricity consumption would be lower than the levels presented in CFP2019, as discussed further in Section 7.2.

[65] Siemens. *Puerto Rico Integrated Resource Plan 2018-2019: Prepared for Puerto Rico Electric Power Authority*. Issued June 7, 2019. Report Number: RPT-015-19. Page 57. Exhibit 3-11.

5 A rate decline for PREPA's services is unlikely

Puerto Rico currently has an average rate of 18.8 cents/kWh (FY 2019).[66] As discussed in Section 4 above, PREPA's current rate is not a full cost of service rate, as it currently excludes the full consideration of previously built assets and financing costs associated with those assets.[67] PREPA's forecast rate for FY 2024 (25.6 cents/kWh) does include the Transition Charge which is expected to pay for (some of the) legacy debt under the Definitive RSA. However, the FY 2024 rate forecast in CFP2019 continues to exclude management fees for third party operators and the capital-related costs for the majority of investments needed for the T&D system in the future.

Other similarly situated island jurisdictions that LEI has selected for comparative analysis have rates that are at or above the current rate in Puerto Rico. These jurisdictions have established regulators who set rates based on well-established regulatory principles of cost recovery and often incorporate incentives for utilities to operate efficiently. Puerto Rico is unlikely to achieve rates in the future that are significantly below the current levels of these other islands.

The long history of PREPA's poor execution in terms of management of fuel purchases, delays in modernization of generation assets and addition of cheaper power sources, and questionable management of finances and contracting services further brings into question its ability to achieve projected rates lower than in other jurisdictions. Multiple experts, as well as the regulator, have questioned PREPA's ability to separate itself from Puerto Rico's political influences and remedy the extensive mismanagement and inefficiency.[68] A T&D operator (concessionaire) will need to address all these issues to be successful. To the extent that commercial incentives can be aligned to harness productivity, it is important to note that efficiency improvements will take time to crystalize. In LEI's experience, transmission and distribution utilities will be cautious in cost-cutting until they have completed a full assessment, which may take months (if not years) to complete.

5.1 Other island utilities have been unable to achieve projected rate declines

Electricity rates for residential, commercial, and industrial customer classes in islands such as Barbados, Bermuda, the Commonwealth of Dominica, Grenada, Hawaii, and US Virgin Islands, and are generally higher than electricity rates in Puerto Rico, as shown in Figure 8 below. This is because running an electric system on an island is expensive. Utility systems on islands are more exposed to weather-driven catastrophes because of their isolated nature and geographical location, have to import essential supplies (which raises operating costs and complicates logistics), and need more redundancy as they lack the ability to coordinate with (and lean on) other interconnected and synchronized electricity systems. Thus, even with regulatory best practices and private ownership in place, LEI still observes high electricity rates on islands.

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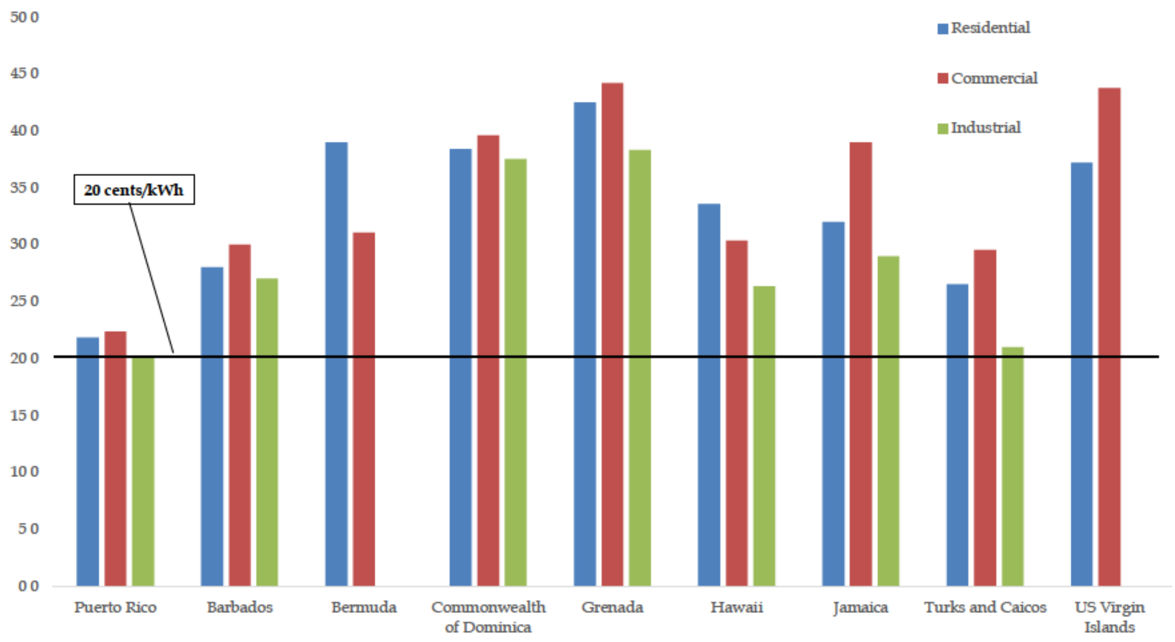
[66] CFP2019, slide 62.

[67] See footnote 40.

[68] *See* PREC. Final Resolution and Order. *Puerto Rico Electric Power Authority Rate Review*. January 10, 2017. *See also* Expert Declaration of Sandra Ringelstetter Ennis. February 25, 2019.

Many of these islands, despite having private utilities that have economic incentives to pursue cost-effective efficiency improvements in order to minimize rates and optimize returns, continue to have high electricity rates. Puerto Rico's legislative goals of keeping all-in rates under 20 cents/kWh appears unrealistic,[69] given actual experience in other, similarly situated island systems where electricity supply is provided by investor owned utilities (as opposed to state-owned utilities) and is regulated by an independent regulator.

Figure 8. Average electricity rates in Puerto Rico versus sample of similarly situated islands (cents/kWh)



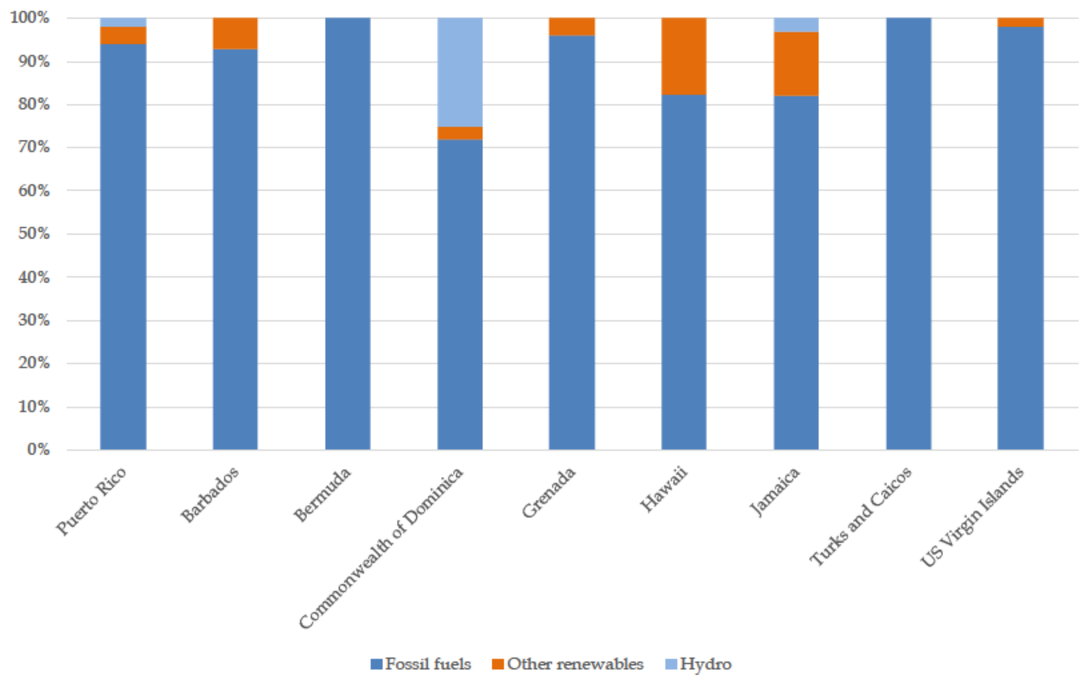
Note: The data in the chart is collected from various sources and covers different timeframes because of data availability. *Barbados:* the electricity rates listed are based on the most recent rate order by the Barbados Fair Trading Commission from February 2010. There have not been any new rate cases since then. *US Virgin Islands*: the residential rate illustrated in the graphic (37.23 cents per kWh) is for the first 250 kWh used. For additional kWh, the rate increases to 39.85 cents per kWh. No industrial rates are available. *Bermuda*: the residential rates assume an average usage of 650 kWh per month and the commercial rates assume an average usage of 3,000 kWh per month.

Sources: *Puerto Rico and Hawaii*: EIA, February 2019. *Barbados, Grenada, Commonwealth of Dominica, Jamaica, and Turks and Caicos*: NREL, 2015. *US Virgin Islands*: Virgin Islands Water and Power Authority, effective as of February 2019. *Bermuda*: Bermuda Electric Light Company (residential rates, 2018) and Government of Bermuda, The Energy Commission, effective as of June 1, 2016.

The primary driver of high electricity rates for many of these islands is heavy reliance on expensive imported petroleum-based fuels for electricity generation. As shown in Figure 9, most of these islands, like Puerto Rico, source over 90% of their installed generation capacity from fossil fuels. Accordingly, their electricity rates are exposed to high delivered fuel costs which account for a large portion of retail rates.

[69] In multiple instances, Act 17-2019 mentions the 20 cents/kWh target.

Figure 9. Installed generation capacity by fuel type for select island electricity systems



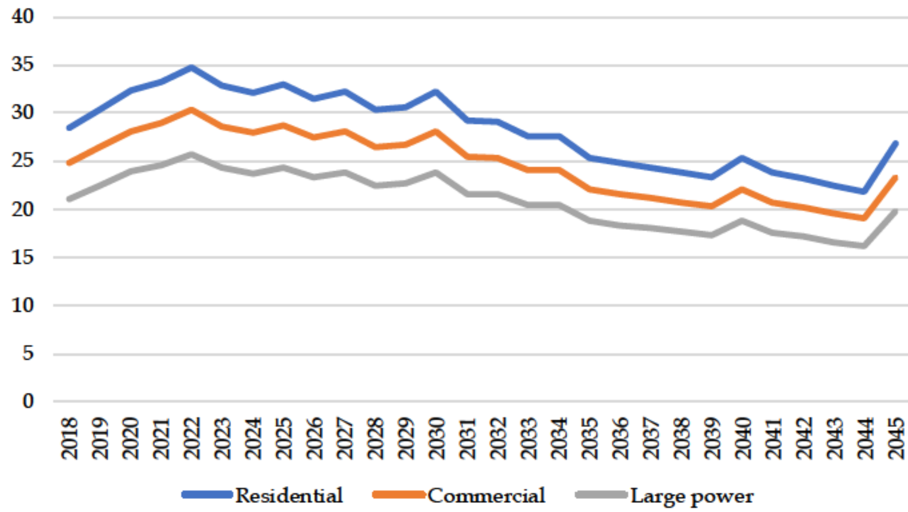
Note: Puerto Rico, Barbados, Bermuda, Commonwealth of Dominica, Grenada, Jamaica, Turks and Caicos, and US Virgin Islands (fossil fuels data 2016, hydroelectric and other renewable sources data 2017), Hawaii (2018).

Source: CIA Factbook. Data as of 2018.

Although a shift to non-fossil fuel fired capacity may reduce rates in the longer term, such supply-driven cost reduction will take time. For example, Hawaii currently aims to meet 39% of its energy needs from renewable energy by 2021 and 100% of its energy needs from renewable energy by 2045.[70] While increasing penetration of renewable energy is expected to reduce fossil fuel costs and over time reduce electricity rates, it will take a significant amount of time to have a material impact on overall rates. As illustrated in the electricity rate projections in Figure 10 below, starting in 2021 (when Hawaii is expected to achieve a 39% renewable energy goal), it will take 24 years (until 2044) for all-in electricity rates to come down by approximately a third from their starting point in 2021.

[70] HECO Companies. *PSIP Update Report*. December 2016, Book 1 (Executive Summary, Chapters 4 and 6) and Book 2 (Appendix D); Hawaii Public Utilities Commission DOCKET No. 2016-0328. Table "Hawaiian Electric Company, Inc. 2017 TEST YEAR. Age of Generating Units – as of 2017;" and KIUC. "Energy Information." <http://website.kiuc.coop/energy-information>

Figure 10. Residential electricity rate projections for Hawaii given renewable energy targets



Source: LEI. "Study to Evaluate Utility and Regulatory Models for Hawaii – Assessment of Projected Average Retail Rates Under Each Regulatory Model." Hawaii State Energy Office. December 28, 2018. Page 676. <https://energy.hawaii.gov/wp-content/uploads/2019/06/Task-2.pdf>.

The second driver of high electricity rates for some of these island systems is higher system losses relative to utility operations on the US mainland (which averages 5% according to the EIA).[71] As shown in Figure 11 below, the comparator islands have total losses (technical and non-technical) ranging from approximately 6% (Hawaii) to 26% (Jamaica). Higher losses translate to significant costs for the utilities (through the need for additional generation, including the costly use of fossil fuels) and that raises final rates to consumers. Puerto Rico has one of the highest percentages of total losses at 17.3% (based on latest data available, for FY 2016).[72]

PREPA notes that it can reduce costs associated with system losses by improving its theft reduction program and reducing its non-technical losses to approximately 3%.[73] Given Puerto Rico's socio-economic situation, achieving such ambitious reductions in non-technical system losses will take major shift in not just utility policies, but also social attitudes to corruption and economic conditions for the electricity consumers that are energy poor (see Section 6.4). This maybe especially challenging given the rate for theft has increased from 2010 to 2016.[74] It is possible that rising electricity rates may lead to increased theft of electricity.[75]

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[71] US Energy Information Administration. "Frequently Asked Questions: How much electricity is lost in electricity transmission and distribution in the United States?" Updated January 9, 2019. <https://www.eia.gov/tools/faqs/faq.php?id=105&t=3>

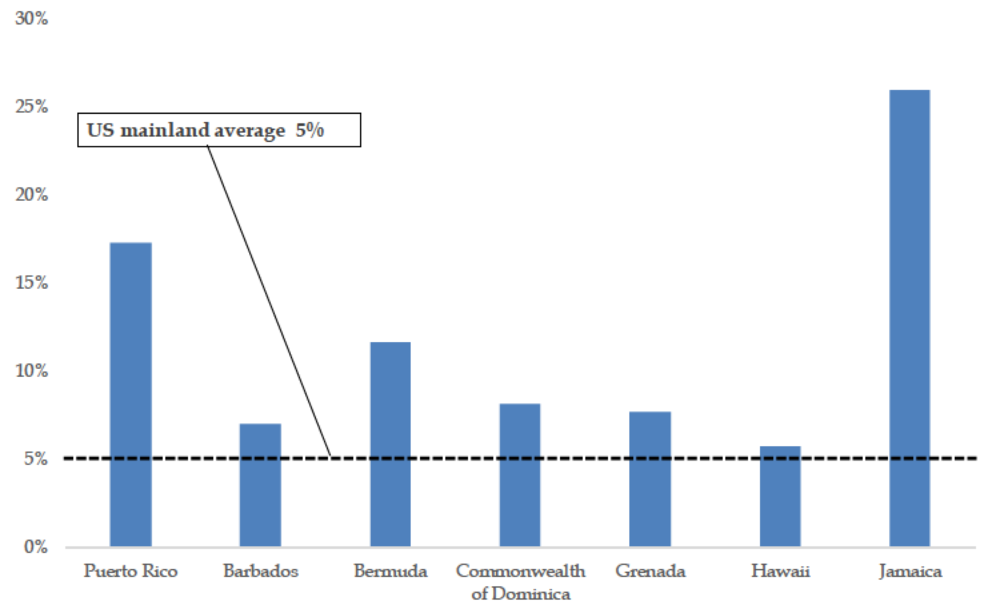
[72] CFP2018, slide 20.

[73] CFP2018, slide 944.

[74] *See* Expert report of Sandra Ringelstetter Ennis. October 3, 2018. Page 23.

[75] *See* Jamil, Faisal and Eatzaz Ahmad. "Policy considerations for limiting electricity theft in the developing countries." *Energy Policy* 129 (June 2019): 452-458.

Figure 11. Technical and non-technical (total) system losses, total



Note: The values listed represent the most recent data available for each island: Puerto Rico (2016), Hawaii (2018), Barbados (2016), US Virgin Islands (2015), Bermuda (2017), Commonwealth of Dominica (2015), Grenada (2015), and Jamaica (2015). Data not available for Turks and Caicos.

Sources: PREPA, Hawaiian Electric Industries, IMF, NREL, World Bank, and the Regulatory Authority of Bermuda.

Puerto Rico also differs from the other islands in quality of service and affordability of rates given income levels of consumers. On average, PREPA customers do not have power for 14.4 hours annually and lose power almost five times a year.[76,77] These values are far worse than industry trends[78] and the experience of some islands. For example, in Hawaii, where electricity rates are, on average, approximately 40% higher than Puerto Rico, customers receive a much more reliable service – the average timeframe for power interruptions is 2.12 hours and this happens only 1.5 times a year.[79] The higher rates in Hawaii, and consumer's willingness to pay for them, is in part reflecting the much higher quality of service. Furthermore, customers in Hawaii are better able to afford such high rates given their relatively high per capita income (as

[76] PREPA. *Puerto Rico Electric Power Authority: Fiscal Plan*. August 1, 2018.

[77] The two values noted represent the System Average Interruption Duration Index ("SAIDI") which measures the average outage duration for utility customers and System Average Interruption Frequency Index ("SAIFI") which represents the average number of interruptions experienced by utility customers. Both of these values are commonly used reliability indicators for electric utilities.

[78] PREPA. *Puerto Rico Electric Power Authority: Fiscal Plan*. August 1, 2018.

[79] Hawaiian Electric. Key Performance Metrics. <https://www.hawaiianelectric.com/about-us/key-performance-metrics/service-reliability>

reflected through Hawaii's GDP per capita, which is approximately 58% higher than that of Puerto Rico).[80]

Figure 12. Key demographic and geographic statistics for other island systems with investor owned utilities, as of 2018

	Population	Total area (Sq. km)	GNP per capita, PPP (current international $)
Puerto Rico	3,294,626	9,104	26,560
Barbados	293,131	430	17,640
Bermuda	71,176	54	66,810
Commonwealth of Dominica	74,027	751	10,680
Grenada	112,207	344	14,270
Hawaii	1,420,000	28,311	61,740
Jamaica	2,812,090	10,991	8,930
Turks and Caicos	53,701	948	24,540
US Virgin Islands	106,977	1,910	29,388

*Hawaii's and USVI's economic activities are reported in GDP per capital terms, PPP.
**Turks and Caicos does not have an independent regulator; ministry regulates the electric utility.

Note: The values listed represent the most recent data available for each island: Puerto Rico, Commonwealth of Dominica, Grenada, Hawaii, Jamaica, Turks and Caicos, and US Virgin Islands (2018), Barbados (2017), Bermuda (2013).

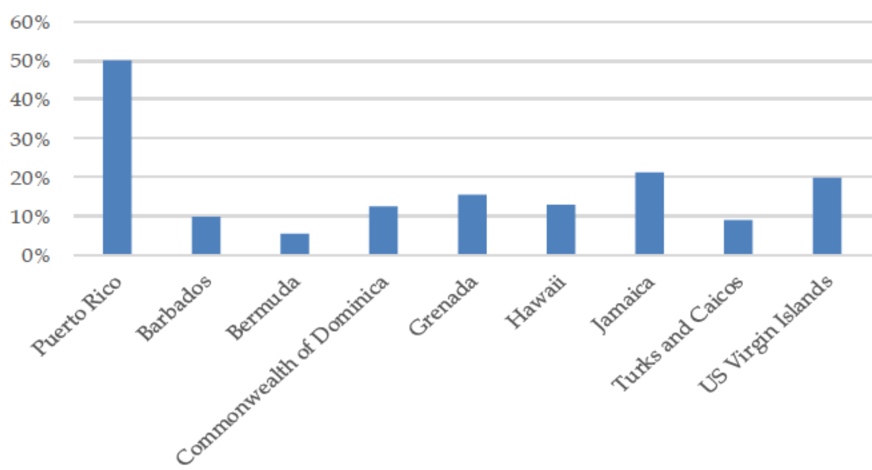
Source: CIA Factbook, World Bank, State of Hawaii Department of Business, Economic Development, and Tourism.

The experience of other islands with investor-owned utilities may lead one to hope that Puerto Rico can also afford higher electricity rates. However, that is not an appropriate conclusion. Many of these other islands have a long history of such high rates, such as Hawaii and Jamaica, while others had even higher rates in the last five to ten years and have started to see decreases

[80] According to the most recent available data from the World Bank (2017), the GDP per capita, PPP (current international $) for Puerto Rico is $39, 092. The GDP per capita for Hawaii (in current US $) is $61,740.

over time, such as Barbados and the US Virgin Islands.[81] The inhabitants and businesses on these islands have already made whatever changes they are going to make to cope with the high rates (consistent with the timeframes typically seen with consumer response under long term elasticity of demand). Conversely, Puerto Rico is in a different situation, where it has had artificially low rates (because PREPA has not been passing through full costs) and where rates need to increase substantially in coming years. Moreover, because it has an unusually high percentage of industrial customers, as shown in the percentage of industry represented as part of GNP in the figure below, Puerto Rico has a much larger group of customers that will be able to transition to procuring electricity service from non-PREPA sources (or leaving the island altogether). This reduction in industrial electricity consumption will result in residential customers being a larger percentage of total load and having to bear the burden of the overall costs of the electricity system. Another key difference to many of the other islands, Puerto Rico has the largest percentage of its population living below the poverty line,[82] creating much more significant challenges for raising rates than what other islands faced.

Figure 13. Industry as sector of origin as percentage of GDP



Source: Hawaii: Department of Business, Economic Development & Tourism; other islands: CIA World Factbook

[81] Hawaii and Jamaica's electricity rates have been mostly stable at around 33 cents per kWh over the past ten years. While Barbados and US Virgin Islands started off with 45 and 55 cents per kWh, respectively, about ten years ago and have , slowly fallen to 26 and 43 cents per kWh, respectively, by 2019. (Sources: US Energy Information Administration. *Electric Power Monthly Report*. (2011 – 2019).; XenogyRE (Press Release). "Average Electricity Cost in Jamaica is Down to Five-Year Low". April 18. 2015. <https://xenogyre.com/2015/04/18/average-electricity-cost-in-jamaica-is-down-to-five-year-low/>; NationNews. "Electricity bills going up". April 12, 2011. <https://www.nationnews.com/nationnews/news/44069/electricity-bills>; GlobalPetrolPrices. Electricity Prices. *Barbados*. June 2018 & March 2019; NREL. *Energy Snapshot: Barbados*. June 2013.; EnergyUseCalculator. Global Electricity Prices. *US Virgin Islands*. 2013; US Virgin Islands Water and Power Authority. *Electric Rate*. (2014-2019).

[82] In Puerto Rico, 44.4% of residents are living below the poverty line, which is higher than the percentages for any of the other islands examined, which range between 10.3% to 38%. *See* United States Census Bureau. QuickFacts. Puerto Rico. July 2018; "Poverty on the Rise in Barbados – Survey". Jamaica Observer. September 14, 2017; DataUSA. Hawaii. 2017; CIA. The World Factbook.

5.2 PREPA has a long history of poor execution

As the sole provider of electricity in Puerto Rico since 1941, PREPA has a long history of poor performance in several aspects of its operations including proper management of its assets and transactions with relevant parties including fuel suppliers and debt providers, among others. PREPA also has a track record of poor execution. PREPA has also been subject to political interference in relationship to labor force, with extensive political appointments.[83] This raises very real questions about PREPA's ability, and the ability of independent operators retained pursuant to generation PPOAs and the T&D concession, to execute on the operational improvement programs that have been identified, as well as to negotiate agreements with third parties[84] that will benefit consumers. It will take time to turn around such an institutional legacy.

5.2.1 Performance of critical business activities has been questionable

PREPA has a track record of poor financial management of its critical operating decisions, which raises questions about how successful it will be in negotiating with vendors to transform their operations in the future. For example, in 2014, when it was unable to afford payments for fuel purchases, PREPA sought to borrow more funds.[85] The FOMB's independent investigator also identified discrepancies in the actual use of proceeds from bond issuances.[86]

Following hurricanes Irma and Maria, PREPA faced scandals regarding contracts to rebuild the island's grid infrastructure. In October 2017, PREPA entered a $300 million contract with Whitefish Energy, a small power company with only two employees and no prior experience in a disaster setting.[87] The contract was later cancelled following multiple Federal inquiries.

On March 5, 2019, PREPA signed an agreement with New Fortress Energy to supply natural gas and rehabilitate two generation units of the San Juan power plant.[88] While the Fuel Sale and Purchase Agreement for the deal was approved by the majority of the Puerto Rico Energy Bureau ("PREB"), it had certain questionable elements. As noted by Associate Commissioner Angel R. Rivera de la Cruz, in the fuel supply agreement PREPA treated capital investment

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[83] *See* Kobre & Kim LLP. *Final Investigative Report*. The Financial Oversight & Management Board of Puerto Rico. August 20, 2018. Pg. 113. <https://assets.documentcloud.org/documents/4777926/FOMB-Final-Investigative-Report-Kobre-amp-Kim.pdf>

[84] Including service providers, fuel suppliers, and future generation developers (and concessionaire)

[85] Walsh, Mary. "Puerto Rico's Power Authority Effectively Files for Bankruptcy." July 2, 2017. <https://www.nytimes.com/2017/07/02/business/puerto-ricos-electric-power-authority-effectively-files-for-bankruptcy.html?module=inline>

[86] Kobre & Kim LLP. *Final Investigative Report*. The Financial Oversight & Management Board of Puerto Rico. August 20, 2018. Pg. 141-147. <https://assets.documentcloud.org/documents/4777926/FOMB-Final-Investigative-Report-Kobre-amp-Kim.pdf>

[87] Newkirk, Vann. "The Puerto Rico Power Scandal Expands." November 3, 2017. <https://www.theatlantic.com/politics/archive/2017/11/puerto-rico-whitefish-cobra-fema-contracts/544892/>

[88] Business Wire. "New Fortress Energy Signs Contract to Supply Natural Gas to San Juan Power Plant." March 5, 2019. <https://www.businesswire.com/news/home/20190305005983/en/New-Fortress-Energy-Signs-Contract-Supply-Natural>

costs as fuel costs even though the associated capital expenditure for the conversion of the units was not part of the most recent revenue requirement approved by PREB.[89]

5.2.2 Mismanagement of fuel purchases

As noted in CFP2018, fuel costs reflected 39% of the operating budget for PREPA and reduction in fuel costs was a major component of the aspirational goals that drove PREPA's vision for future rates.[90] Fuel management is a critical component of historical costs and future rates. As oil prices will continue to be a function of global market prices, PREPA's ability to materially manage those commodity price swings is limited.

PREPA has faced longstanding accusations that its fuel purchasing office was involved in a scheme in which it purchased low-quality oil from oil suppliers at high-quality prices and charged consumers rates based on the higher prices.[91] According to a Puerto Rico Senate report from 2016 which outlines details on the scheme involving PREPA, oil suppliers, and oil-testing laboratories, the costs incurred as a result of this scheme, in addition to being passed on to consumers, were financed through additional borrowing and reallocation of resources from other operational needs.[92] The report also notes that PREPA's Fuel Office was given full discretion over acquiring large volumes of oil, and that oil suppliers were essentially operating in a "cartel" setting, which then gave them control over the fuel prices charged through to PREPA's customers.[93]

5.2.3 Delays in implementing plans for modernization of generation assets and addition of cheaper power sources

Efforts to modernize PREPA's old fossil fuel generating plants and shift towards cheaper power sources have been deferred and delayed on multiple occasions.

PREPA's generation assets have systematically underperformed relative to its peers. PREPA itself noted that its assets have outage rates that are 12 times higher than its peers in mainland US.[94] According to the Puerto Rico Energy Commission ("PREC"), the predecessor to the PREB, the poor performance of PREPA's generation assets is attributed to "systematic maintenance failures, a failure to perform predictive maintenance, operational errors, and faulty repairs."[95]

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[89] PREC. CEPR-AI-2018-0001. "Request for Proposals for conversion of San Juan Units 5 & 6 to natural gas." January 25, 2019. Pg. 3 of 7.

[90] CFP2019, slides 26 and 44.

[91] Walsh, Mary. "Puerto Rico's Power Authority Effectively Files for Bankruptcy." July 2, 2017. <https://www.nytimes.com/2017/07/02/business/puerto-ricos-electric-power-authority-effectively-files-for-bankruptcy.html?module=inline>

[92] Puerto Rico Senate, Special Commission for the Study of the Standards and Procedures Related to the Purchase and Use of Oil by the Puerto Rico Electric Power Authority and of Government Integrity, Final Report, December 5, 2016.

[93] ibid, page 91

[94] CFP2018, slide 20.

[95] PREC. Final Resolution and Order. Puerto Rico Electric Power Authority Rate Review. January 10, 2017. P. 66.

PREPA's renewable build out has also had a checkered past. For example, project developers under executed Renewable PPOAs with PREPA experienced significant challenges and delays due to PREPA's mismanagement of the interconnection process for new projects.[96]

Stakeholders have also noted that PREPA's board of directors and management have been too exposed to political interference, which has delayed integrated resource planning and rate hearings.[97] The history of animosity between PREPA and the regulator[98] has also been well documented, and this tension increases the regulatory burden on both PREPA and the regulator, which indirectly but materially impacts consumers. Increased regulatory and legal costs will flow through the labor and operations budgets, while delays in approvals for necessary capital investments can create significant lost opportunity costs.

5.2.4 Project 180 delays

PREPA has disclosed delays in its Performance Improvement Initiative (Work Plan 180). Specifically, PREPA's management has noted in their monthly reports to the FOMB that certain initiatives have been put on hold, either because the initiatives turned out to be questionable or because of "work force" limitations.[99] FOMB has also recently chastised PREPA for going over its budget by nearly $13 million because of overtime pay, utilities, rent, and support for P3 Authority transactions (which relate to the competitive solicitations for new generation projects and a T&D concessionaire).[100] Given PREPA's recent track record, labor and non-labor O&M cost reductions assumed in CFP2018 and CFP2019 are by no means guaranteed.

5.3 New generation will take time to bring online

Rates are not expected to come down as quickly as PREPA anticipates in CFP2019, given the process involved for soliciting new generation investment and negotiating new PPOAs. Generation capacity additions follow a multi-year structured process that may include delays. Indeed, delays are to be expected given the volatility of the current political and financial situation. As mentioned in CFP2019, the San Juan fuel conversion has fallen six months behind the initial scheduled due date; there were delays in the FEMA application process for the utility scale energy storage RFP; the schedules for RFPs for hydroelectric program upgrade and replacing PREPA's peaking units have not yet been determined.[101]

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[96] US District Court for the District of Puerto Rico. Motion for relief from automatic stay and to compel the Puerto Rico Electric Power to assume or reject the executory contract. Case No. 17-BK-4780-LTS. P 3-9.

[97] PREPA. *PREPA's Transformation: A Path to Sustainability*. June 1, 2015. <http://www.gdbpur.com/documents/PREPARecoveryPlan6-1-15.pdf>

[98] Velez, Eva. "Puerto Rico Electric Power Authority Under Risk of Receivership." March 7, 2019. <https://caribbeanbusiness.com/puerto-rico-electric-power-authority-under-risk-of-receivership/>

[99] For example, according to a February 2019 monthly status report to the FOMB, only 2 of its 21 initiatives (approximately 10%) have been completed while the remaining are either "At risk," "On hold," or "Not on Track." *See also* Expert Declaration of Sandra Ringelstetter Ennis. February 25, 2019.

[100] Jaresko, Natalie A. Financial Oversight and Management Board for Puerto Rico. "To Mr. José F. Ortiz Vázquez." May 29, 2019. Letter. <https://drive.google.com/open?id=1aW8AtX8YgG6sHzlIy6Y4FT1r7ZdCwAb0>

[101] CFP2019, slide 28 and slide 91.

CFP2019 forecast a very aggressive build out of new renewable generation: 101 MW of wind and 1,074 MW of solar by FY 2025.[102] Although construction of such facilities does not take more than a few years, the permitting, interconnection, and contract negotiations add to the development time and can extend the commercial operational dates a few years. This is especially likely in Puerto Rico because competitive procurements conducted by the P3 Authority[103] use a multi-staged approach:[104]

- *Market sounding process:* P3 Authority may seek feedback from market participants to determine the best approach to selecting viable transactions for PREPA.
- *Request for Qualification ("RFQ"):* P3 Authority will issue an RFQ in relation to a transaction. Proponents must meet minimum financial, technical, and professional standards. The RFQ will be announced as a public notice.
- *Request for Proposal ("RFP"):* RFPs are required to be public and published on the websites of P3 Authority and PREPA, and other national and international journals and newspapers if needed. Requests for Clarification ("RFC") may be requested up to 15 days prior to the due date of an RFP.
- *Evaluation and selection process:* a partnership committee follows a three-phase evaluation, selection, and negotiation process. First, the committee must determine within 10 business days of the due date of submission of proposals, whether proposals have passed the evaluation criteria. Second, the committee reviews proposals that have passed, and make a recommendation of one or more proposals. Finally, if needed, the committee would negotiate with one or more of the "shortlisted" proponents.

IRP 2019 outlines that proposed capacity additions will take between four and five years to reach commissioning. The first phase includes the procurement process outlined above, which is followed by obtaining the necessary permitting and financing. The second phase involves the implementation of the project via Engineering Procurement and Construction ("EPC"), which leads to the commercial operation of a project. The IRP notes that "there is a potential that an unforeseen issue may prevent or significantly delay some of the planning solar PV and/or gas fueled generation additions."[105] Public information on progress has been limited: in CFP2019, the "Due Date" for renegotiating PPAs with 11 shovel ready renewable projects was still

[102] CFP2019, slide 20.

[103] Act 120-2018 approved on June 21, 2018, designated P3 Authority as the sole entity authorized and responsible for the procurement and sale of power generation assets, including the solicitation process, selecting entities and individuals entering into contracts with PREPA. *See:* Government of Puerto Rico. Office of Legislative Services. Act No. 120-2018. June 21, 2018. <http://www.oslpr.org/download/en/2018/A-120-2018.pdf>

[104] Government of Puerto Rico Public-Private Partnerships Authority. *Regulation for the Procurement, Evaluation, Selection, Negotiation and Award of Partnership Contracts and Sale Contracts for the Transformation of the Electric System under Act No. 120-2018, As Amended.* Date of Approval: March 8, 2019. <http://www.p3.pr.gov/assets/p3a-act-120-regulations-eng.pdf>.

[105] In recognition of this risk, IRP 2019 proposed the Mayaguez and Costa Sur CCGT projects as hedges against delays in the implementation of other projects or terminals; development of these hedges are expected to commence alongside other projects, but will only enter the EPC stage if needed. Source: IRP 2019, page 1-11 (PDF page 23).

marked as "TBD." Selection of winners in the utility-scale energy storage procurement has been delayed.[106]

5.4 New wires operator will also need time to mobilize; T&D efficiency gains will take time to realize

The premise of privatization is based on the assertion that private, for-profit operator and owners will have stronger incentives than government-owned enterprises to reduce costs. However, that premise is contingent on a regulatory design that provides for such economic incentives to the new private operators/owners, through incentive-based rate design, and also ensures that such economic incentives are sufficient (including providing for a reasonable timeframe for costs to be rationalized and adjusted). Moreover, customers' interests – specifically the quality of service – must be protected in the face of cost cutting by the private operator/owner. Potential operating efficiency gains from privatization and regulatory reforms are well documented. The experience of National Grid in the UK after privatization is indicative of the operating gains potential for electric wires business. The operating costs of the 12 UK regional electricity companies fell by 3.03% per annum between 1990 and 1997, after industry reforms.[107,108] These are illustrated in Figure 14 below. Notably, the UK utilities experienced about a 20% cumulative reduction in costs over a seven-year period, but the cost reductions took several years to take root (as seen in the figure below).

In Australia, privatization in the states of Victoria and South Australia also provide some useful benchmarks for realized cost reductions in network costs. Following sector deregulation, realized network cost reductions range from 17% over a 12-year period in South Australia to 18% over a 17-year period in Victoria.[109]

By comparison, PREPA was originally suggesting it could reduce its non-fuel labor and operating costs by up to 21% over five years in CFP2018.[110] In CFP2019, PREPA has stepped back from its initial aggressive goals and assumed a more modest cumulative reduction of 6% over five years.[111]

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[106] CFP2019, slide 28.

[107] Domah, P. and M. Pollitt. *The Restructuring and Privatisation of the Electricity Distribution and Supply Businesses in England and Wales: A Social Cost Benefit Analysis*. July 2000.

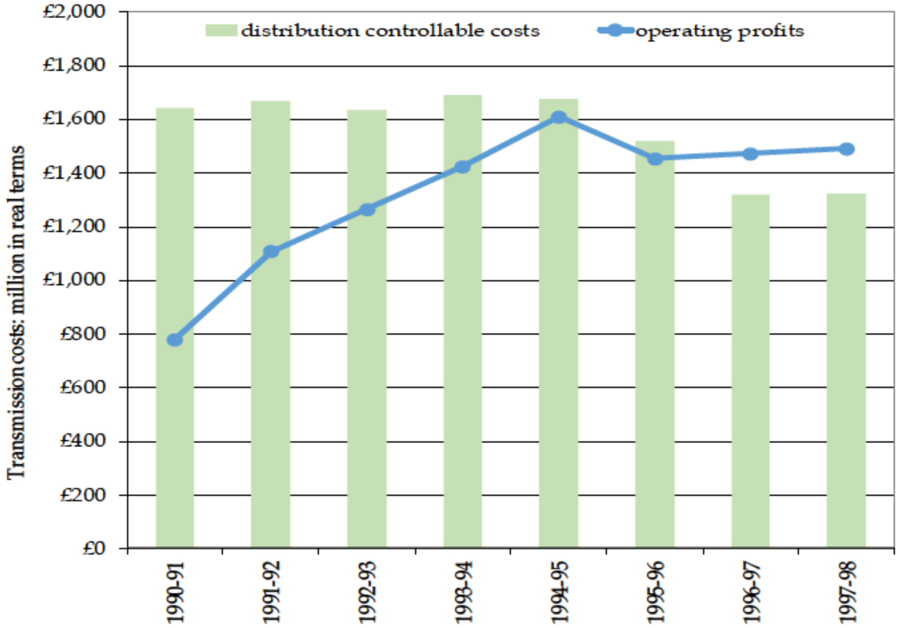
[108] Office of Gas and Electricity Markets. *Electricity Distribution Cost Review*. December 2005.

[109] In Australia, the State of Victoria corporatized and privatized its electricity network between 1995 and 1999; over the 1996 to 2013 period, network costs in Victoria declined by 18% in total. In the State of South Australia, network costs declined by 17% between 1998/1999 and 2010/2011, following the privatization of South Australia's electricity sector by the year 2000. Source: Nepal, Rabindra and John Foster. "Electricity Networks Privatization in Australia: An Overview of the Debate." *Economic Analysis and Policy Journal* 48 (December 2015): 12-24.

[110] CFP2018, slide 50.

[111] This percentage reduction is calculated as the decline in total (non-fuel) operating costs, namely "Labor Operating" and "Non-Labor/Other Operating" costs, between FY 2020 and FY 2024, excluding a one-off $50 million Title III restructuring cost in FY 2020. *See* CFP2019, slide 69.

Figure 14. Controllable costs and profits for UK's regional electricity networks (1990 to 1998)



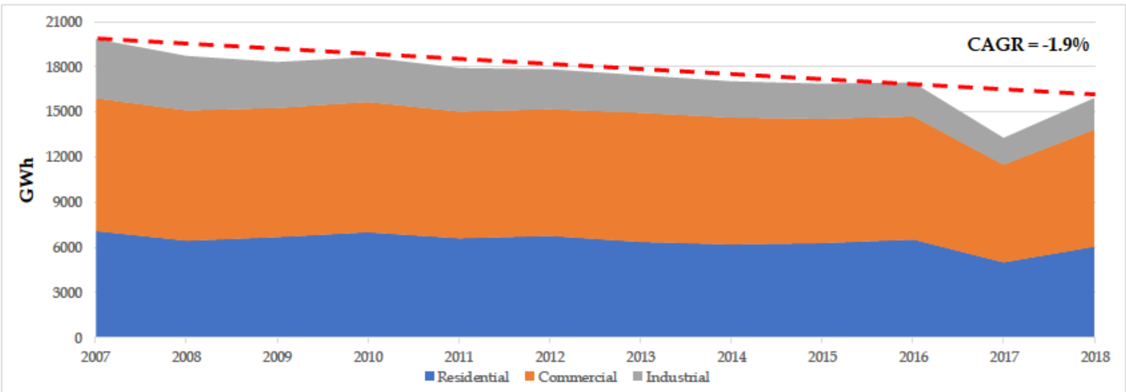
Note: REC controllable cost are the controllable costs of both the supply and distribution businesses aggregated (total operating costs less National Grid Company exit charges, depreciation, and exceptional costs).

Source: Domah, P. and M. Pollitt. *The Restructuring and Privatisation of the Electricity Distribution and Supply Businesses in England and Wales: A Social Cost Benefit Analysis*. July 2000.

6 Future demand for electricity in Puerto Rico is likely to be lower than it is today

Economic slowdown and population trends (outward migration) have led to an increasingly challenging environment for PREPA in terms of electricity demand. Annual electricity consumption declined by 12.1% between 2007 and 2018, with the largest decline in the industrial sector.[112] As shown below in Figure 15, overall electricity demand between 2007 and 2018 has declined by 19.7%; the observed Compound Annual Growth Rate ("CAGR") in electricity demand over this period was -1.9% per annum.

Figure 15. Historical electricity sales in Puerto Rico



Source: Historical sales figures based on data collated from PREPA. *See* PREPA. Statistics. "Documents Related to Law 57-2014." Website. <https://aeepr.com/es-pr/quiénes-somos/ley-57>; <https://indicadores.pr/dataset/generacion-consumo-costo-ingresos-y-clientes-del-sistema-electrico-de-puerto-rico>.

As rates continue to increase, LEI expects that the future will yield further reductions in demand for electricity. Reduction in electricity demand may occur for a variety of reasons, including: in response to changes in circumstances for customers (for example, when a business closes or a household leaves its residence and that vacancy remains); technology improvements (for example, more efficient appliances); or because customers are responding to price increases (which can be estimated by evaluating price elasticity of demand). Demand reductions may also arise due to externally funded incentives to reduce demand (such as the technical energy efficiency programs presented in IRP 2019) or concerns about quality and affordability of service. Some customers may install distributed generation systems to reduce consumption (for economic or other reasons[113]) or disconnect completely from the grid and implement self-supply options. If higher electricity rates also slow economic activity, as many economists have warned, there may be recursive effects on electricity demand in the longer term. The interplay of rates and economic conditions may also increase electricity theft (e.g., non-technical losses).

112 Energy Information Administration. *Electric Power Monthly*. Table 8.1 Puerto Rico - Sales of Electricity to Ultimate Customers. May 2019.

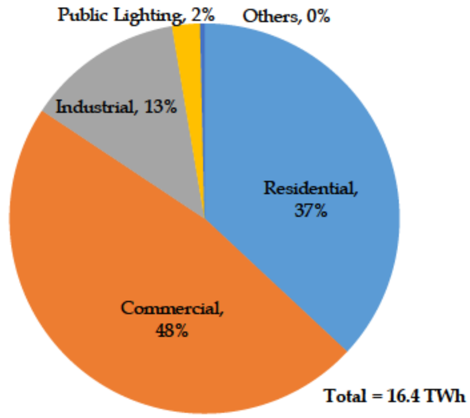
113 Laws, Nicholas D., et al. "On the utility death spiral and the impact of utility rate structures on the adoption of residential solar photovoltaics and energy storage." *Applied Energy* 185 (2017): 627-641.

In this section of the Report, LEI evaluates the sustainability of projected rate increases by first considering the demand elasticity of load and its impact on long-term demand. LEI then evaluates the alternatives to grid supply for large customers and wealthy customers through self-supply via distributed energy resources ("DERs"), as well as consider the implications of energy poverty and Puerto Rican households' ability to pay increased electricity rates.

6.1 PREPA's current customer mix

PREPA's customer profile is comprised of commercial, residential and industrial customers, with their respective load shares illustrated in Figure 16 below. Currently, commercial customers comprise the largest segment of electricity consumed on PREPA's system (at 48%), while residential customers are 37%, and industrial customers are only 13% of the total demand. The distribution of revenues from customers is similar to the breakdown of annual consumption.

Figure 16. Distribution of PREPA's electricity sales by customer class



Sources: PREPA. 2019 IRP. Exhibit 3-2. June 7, 2019.

PREPA's (and their consultant's) forecasts suggest that a further decline in total electricity demand is imminent. The IRP 2019 anticipates that residential and commercial demand will decline. The IRP forecasts that annually, over the 2019-2038 period, commercial and residential sales will decline by 3.67%, and 2.47% respectively, on an annual basis.[114] CFP2019's forecast covers FY2020 to FY2024, and within that period, sales are expected to decrease from 15,832 GWh in FY2020 to 13,150 GWh in FY2024, a decrease of 17%.[115] The largest declines are occurring in the residential and commercial customer classes. Siemens utilized population and GNP forecasts to develop their forecast for IRP 2019.[116] The IRP 2019's Reference Case projection of gross electricity sales (before energy efficiency and customer-owned generation)

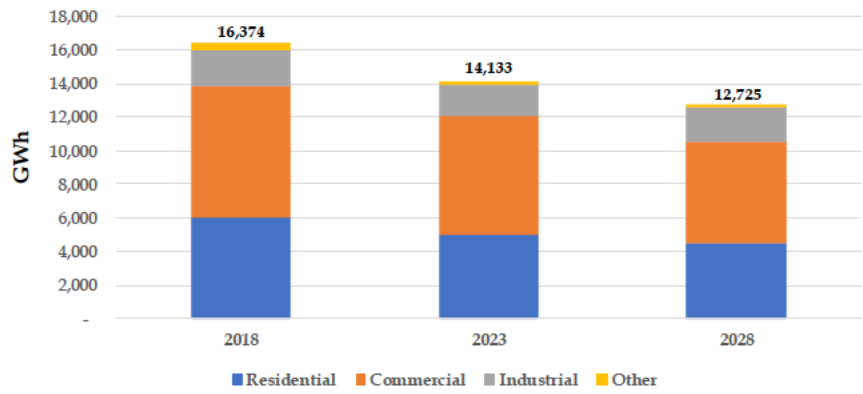
[114] Including energy efficiency per exhibit 3-14 of June 2019 IRP. Source: Siemens. *Puerto Rico Integrated Resource Plan 2018-2019: Prepared for Puerto Rico Electric Power Authority*. Issued June 7, 2019. Report Number: RPT-015-19.

[115] PREPA. 2019 Fiscal Plan for Puerto Rico Electricity Power Authority. June 27, 2019.

[116] The IRP 2019 Reference Case forecast utilized population and GNP forecasts from FOMB. The IRP also considered other sources. For population, the IRP compared third-party population forecasts between FOMB, US Census, Moody's and IMF, and selected the FOMB forecast, which is around the middle of the four forecasts reviewed. For GNP, the FOMB forecast is aligned with the IMF forecast but lower than the Moody's forecast.

exhibited a 5% reduction between 2018 and 2023. However, Siemens also estimated electricity consumption reductions from energy efficiency programs and customer-owned generation.[117] Total electricity demand net of energy efficiency was projected to be 13.6% lower relative to 2018 demand, as show in Figure 17 below.[118] In turn, CFP2019 relies on the electricity demand projections from IRP 2019. Notably, however, CFP2019 does not appear to incorporate Siemens's forecast of customer-owned generation into its demand trends.[119]

Figure 17. IRP 2019 load forecast – including energy efficiency



Sources: Siemens. *Puerto Rico Integrated Resource Plan 2018-2019: Prepared for Puerto Rico Electric Power Authority*. Issued June 7, 2019. Report Number: RPT-015-19. Exhibit 3-14.

IRP 2019 does not incorporate how rate changes will impact demand for electricity. Economic theory suggests that electricity demand is subject to price elasticity, but Siemens appears to have dismissed this effect based on certain limited historical data it reviewed.[120] Historical observations regarding industrial demand in select years are not sufficient reasons for ignoring the phenomenon of demand elasticity for the future. From 2000 to 2017 (the period that Siemens analyzed for correlation between industrial rates and demand), there were other drivers that caused industrial electricity demand to fall (industrial customers were leaving the island for various reasons, including (but not limited to) expiration of tax exemptions). The impact of these factors may have created more downward pressure on electricity demand than the positive impact of a handful of years of declining rates. Therefore, those experiences in Puerto Rico are not demonstrative of a conclusion that there is no price elasticity of demand in Puerto

[117] In the IRP, Siemens does not break down customer sited generation by customer type, and as such could not be included in the analysis. See exhibit 3-14 and 3-18 of Integrated Resource Plan (2018-2019). June 2019.

[118] Exhibit 3-14 of the IRP notes that the forecasted sales demand after energy efficiency programs is 14,133 GWh in 2023, which represents a 13.6% decline from 2018 load of 16,374. Source: Siemens. *Puerto Rico Integrated Resource Plan 2018-2019: Prepared for Puerto Rico Electric Power Authority*. Issued June 7, 2019. Report Number: RPT-015-19.

[119] In the IRP, energy efficiency programs are assumed to meet the requirement of Act 17-2019, which anticipates 2% per year of incremental savings attributable to new energy efficiency programs through 2037. Siemens also incorporates naturally occurring technological advancements into EE, such as more efficient household appliances.

[120] Siemens stated in the IRP that "customer rates were considered in the analysis, in particular industrial rates, but they were found not to have a strong historic correlation to demand and explanatory power. From 2000 to 2017, there were periods where industrial demand fell along with declining industrial rates or the opposite.... However, sustained high retail rates could change customer behavior and create more incentives for implementation of energy efficiency programs." *See* IRP 2019, page 51.

Rico. Moreover, the rate increases in CFP2019's forecast and longer-term rate increases required by the Transformation that Siemens studied in the IRP 2019 are more likely to trigger consumer behavior changes than rate fluctuations during the 2007-2017 period.

6.2 As electricity rates increase, demand for electricity should decline

Consumers' response to rising rates needs to be factored into electricity demand forecasts. Consumption habits for most goods have an inverse relationship with price, and electricity demand is no exception. As prices rise, LEI would expect demand to fall. This is referred to as the price elasticity of demand. In the electricity sector, this price elasticity of demand will grow with time, as consumers have more technically and economically feasible options and therefore are more willing to change consumption behavior. Demand response to price changes is critical in determining the optimum level of investment in generation and transmission capacity.[121] Multiple government institutes, think tanks, and university research institutes have conducted studies on the price elasticity of electricity demand, to assess trends in the industry and investigate policy effectiveness. LEI has surveyed relevant research regarding the price elasticity of demand for electricity, shown below in Figure 18.

The price elasticity of demand is expressed mathematically as a measure of the percentage change in quantity demanded against the percentage change in price, or log change in demand or log change in price, depending on the methodology used by the study. The surveyed studies for price elasticity of demand provide important insights regarding consumer habits. All observed price elasticity of demand figures are negative, which is expected given the logically negative correlation between price and demand for electricity. Therefore, a price elasticity of demand value of -0.3 would signify a reduction of 3% in demand for a 10% increase in prices.

In LEI's professional opinion, utilizing long-run elasticity is more applicable to studying load forecast impact. Long-run elasticity assesses the adaptability of consumers over a longer period of time to rate (price) changes, while the short-run may include demand response and load-shifting activities that are immediately available to consumers. The price elasticity of demand is higher over the long-run, compared to the short-run. Demand reduction is more dynamic in the long-run as consumers would have a longer timeframe to react to the increased prices,[122] through the purchase of new, more efficient appliances, behavioral changes (to conserve energy), and substitution between various energy sources (e.g., switching to using distributed solar PV).

[121] Deryugina, Tatyana et al. The Long-Run Elasticity of Electricity Demand: Evidence from Municipal Electric Aggregation. May 2017.

[122] A study of demand elasticity for consumers in Illinois showed an elasticity of -0.14 in the first year, -0.27 in the second year, and between -0.29 and -0.39 for three years onwards. Source: Deryugina, Tatyana et. al. *The Long-Run Elasticity of Electricity Demand: Evidence from Municipal Electric Aggregation*. May 2017.

Figure 18. Sample of findings from electricity demand elasticity studies

Study	Author(s) or publisher	Year of publication	Jurisdiction	Notes	Elasticity of demand	
					Short-run	Long-run
1	Alberini, Filippini	2011	US	Cross-sector elasticity of demand	-0.1	-0.7
2	Burke, Abayasekara	2017	US	Cross-sector elasticity of demand	-0.1	-1
3	Deryugina, MacKay, Reif	2017	Illinois	Cross-sector elasticity of demand	-0.205	-0.39
4	Electric Power Research Institute	2008	US	Residential sector elasticity	-0.3	-0.9
5	Energy Information Administration	2014	US	Residential sector elasticity	-0.19	-0.4
6	Energy Information Administration	2014	US	Commercial sector elasticity	-0.19	-0.82
7	Energy Information Administration	2017	Mexico	Cross-sector elasticity of demand	-0.35	-0.57
8	Faruqui, Sergici, Lessem, Mountain	2014	Ontario	Impact of time-of-use rates	-0.12 to -0.27	-
9	National Renewable Energy Laboratory	2005	US	Cross-sector elasticity of demand	-0.24	-0.32
10	Paul, Myers, Palmer	2009	US	Cross-sector elasticity of demand	-0.13	-0.36
				Average	-0.22	-0.61
				Median	-0.19	-0.57
				Maximum value	-0.1	-0.32
				Minimum value	-0.35	-1

Sources: Multiple; please refer to list of works consulted

Based on empirical studies, it has also been observed that lower income individuals are more sensitive to prices. From the figure above, the observed cross-sector elasticity of demand in Mexico in the short-run is higher than any of the studies that observed elasticities in the US and Canada. Moreover, a survey of economic literature shows that electricity demand is positively responsive to income increases.[123]

6.3 Distributed Energy Resources ("DERs") provide alternatives to grid-connected service for high income residential, as well as commercial and industrial customers

Rapidly declining technology costs suggest that alternatives to receiving power supply from PREPA may increasingly become an economic option for those customers that can finance such investments on their own. Analysis using reasonable cost estimates for self-supply suggest that a renewable system with backup would be cheaper than PREPA's all-in rate as early as 2021.

6.3.1 Evolution of levelized costs for renewables

In recent years, Levelized Cost of Energy ("LCOE")[124] estimates for renewables have followed a dramatic downward trajectory because of declining capital costs for system components, improvement in the efficiency of the technologies, and economies of scale resulting from increasing maturity of the technology, decreasing supply chain costs, and intense competition among vendors.[125, 126] The historical pattern of LCOEs over time for utility-scale and distributed

[123] A survey of demand elasticity studies determined the long-run income elasticity of electricity demand to be 0.90 (Source: Campbell, Alrick. "Price and Income Elasticities of Electricity Demand: Evidence from Jamaica." *Energy Economics* 69 (January 2018): 19-32).

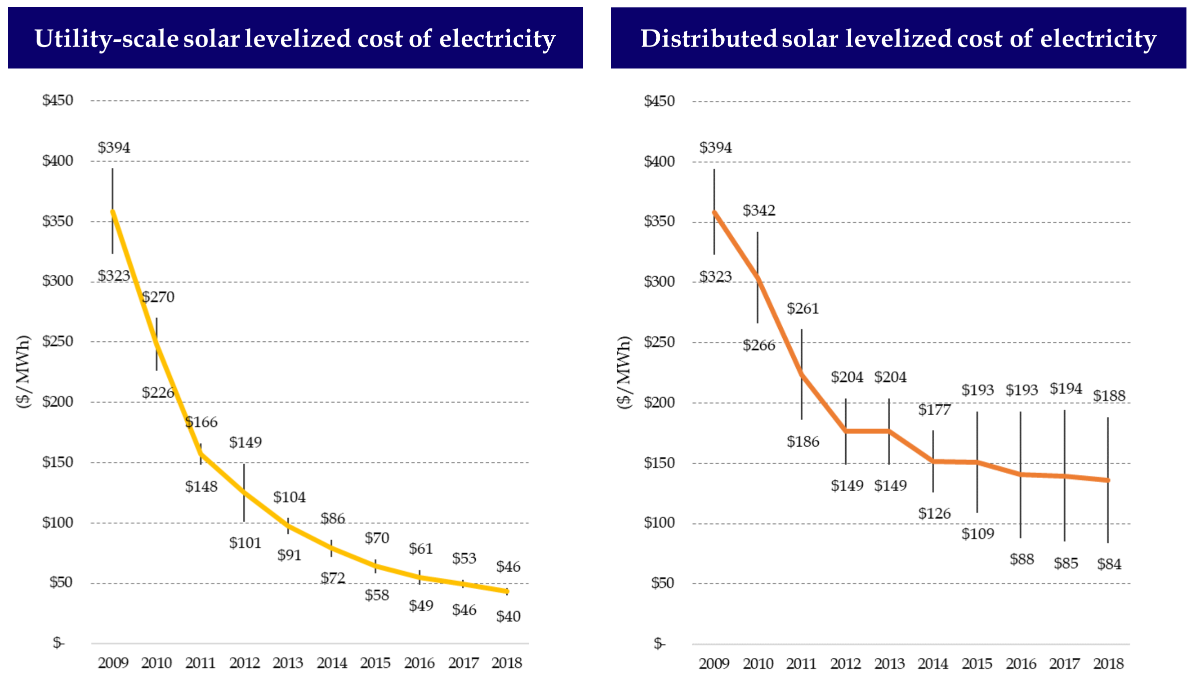
[124] Levelized Cost of Energy ("LCOE") is defined by the EIA as the "average revenue per unit of electricity generated that would be required to recover the costs of building and operating a generating plant during an assumed financial life and duty cycle." In other words, an LCOE value illustrates the average lifetime cost for the energy produced by various energy systems, given in today's prices (Source: EIA. *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2019*. February 2019).

[125] EIA. Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2019. February 2019.

[126] Lazard. Levelized Cost of Energy Analysis 12.0. November 2018.

solar PV are illustrated in Figure 19. The graphic shows an average annual decline in costs of 10% for distributed solar PV and 21% for utility scale solar PV. However, the pace of improvement is slowing. Specifically, annual reductions in LCOEs in the last five years has fallen to 5% for distributed solar and 15% for utility-scale solar.[127]

Figure 19. Historic solar LCOEs for utility scale and distributed generation scale



Sources: Lazard. *Levelized Cost of Energy Analysis*. November 2018.

The integration of storage technologies such as batteries with intermittent renewable operation improves the reliability of operations of intermittent resources. Utility and consumer adoption of paired solar PV and battery solutions is increasing (in Puerto Rico[128] as well as in other jurisdictions). Such a combination is the most relevant for an assessment of PREPA's future load, as customers would need to completely disconnect from the system in order to avoid the full Transition Charge.

6.3.2 What is the cost of off-grid (self) supply?

Self-supply, also known as "grid defection," can occur when a customer perceives that stand-alone self-supply solutions are preferred over buying electricity from the utility grid. Projected rates for PREPA will be well over 20 cents/kWh in the short term, as forecast by CFP2019 and as projected by LEI in its forecast of rate (see Section 7). For financially secure industrial customers, it may be economical to leave the grid and supply needs through a range of configurations of DERs (or BTMGs), including fossil-fuel configurations of reciprocating

[127] Ibid.

[128] See footnote 129.

engines (with redundancy) or solar PV plus backup solutions (battery or reciprocating engine). Commercial and residential customers may opt for smaller scale DERs, such as solar PV distributed generation ("DG"), which may include battery storage. Indeed, some customers in Puerto Rico have already migrated to off-grid electricity solutions.[129] Similar opportunities have been realized in other island system were rates are high and service quality subpar.[130]

LEI undertook an illustrative analysis of configurations that can be used for off-grid, self-supply in Puerto Rico to test the economics of grid defection. LEI considered three configurations tailored around a notional large commercial or industrial customer consuming 8,760 MWh of electricity annually and having a peak demand of 1 MW. In recognition of the intermittency of renewable DERs, all the options were designed to ensure redundancy and backup power so that customers could reliably[131] meet their annual consumption needs without for the necessity of grid supply:[132]

(i) *Case 1: Solar + battery storage*: this configuration pairs a 6 MW solar PV plant which is backed up with a 1.5 MW (12 MWh) Lithium-ion battery;

(ii) *Case 2: Solar + fossil fuel (diesel) generator*: in this configuration, a 4 MW solar PV plant is backed up by a 1 MW diesel generator; and

(iii) *Case 3: Fossil-fuel only*: for this configuration, the industrial consumption is met by a 2 MW dual fuel standard reciprocating internal combustion engine ("RICE") generator, whose primary fuel is natural gas; the large size provides redundancy.

To evaluate each case, LCOEs were determined using the parameters described above, and compared with average PREPA customer rates as detailed in CFP2019. A simplified LCOE formula is given below, providing a standard metric to compare various technologies, and to compare to the delivered rates for PREPA:

$$LCOE = \frac{\sum Lifetime\ costs\ (\$)}{\sum Lifetime\ energy\ produced\ (kWh)}$$

129 Merchant, Emma. "Grid Defection is On the Rise in Puerto Rico." *Green Tech Media*. February 16, 2018. <https://www.greentechmedia.com/articles/read/grid-defection-on-the-rise-in-puerto-rico>

130 University of the West Indies announced it will use gas turbines to leave the grid in Jamaica. (*Source:* Ellsmoor, James. "The New Age of Electricity – Utilities in 2019." January 31, 2019. <https://www.forbes.com/sites/jamesellsmoor/2019/01/31/the-new-age-of-electricity-utilities-in-2019/#78fbd25f4299>).

131 PREPA's quality of service has been subpar historically, so the issue of quality of supply may be less of a concern for a customer looking to disconnect from the grid, especially if he can reduce the risk of interruptions through redundant system components.

132 For Case 1: Solar + storage, LEI has scaled the solar and battery installations to handle weather variations. For Case 2: Solar + RICE, LEI assumes the RICE unit will run with an average load factor of 20% to produce energy generation when solar unit is not generating. For Case 3: LEI assumes two RICE units, with cumulative average load factor of 50%, one unit will be operating in baseload model, while the second unit is providing backup capacity.

General assumptions for all the cases were taken from publicly available references[133,134] and also take into account Puerto Rico-specific assumptions as detailed in the most recent Puerto Rico IRP (prepared by Siemens) and Certified Fiscal Plans.[135,136] These assumptions are summarized in Figure 20 below.

Figure 20. Assumptions for LCOE calculations for self-supply systems

Item	Unit	Assumption for FY2020	Sources/Notes
Capital cost (Solar)	$/kW	1,060	NREL. *2019 Annual Technology Baseline.* Utility scale PV mid case
Capital cost (Storage)	$/kW	2,394	Lazard. *Levelized Cost of Storage Analysis Version 4.0* , average of T&D level lithium storage, adjusted to 2020
Capital cost (Recip engine)	$/KW	1,755	NYISO. *Staff Recommendations - ICAP Demand Curve Reset.* September 2016. Adjusted to 2020 for Wartsila 18V50 in Zone F
Solar capacity factor	%	22	*Puerto Rico Integrated Resource Plan (2019-2019).* June 2019. page 133
Puerto Rico overnight capital cost adde	%	16	*Puerto Rico Integrated Resource Plan (2019-2019)* . June 2019. page 145
Weighted Average Cost of Capital ("WACC")	%	12.85	LEI assumption, as compared to 8.5% in IRP 2019 Exibit 6-1
Project life	Years	20	EIA. *Assumptions to the Annual Energy Outlook* , January 2019
Fuel prices (Diesel)	$/MMBtu	16.4	LEI assumption, as compared to $17/MMBtu in CFP2019 slide 59
Fuel prices (Natural gas)	$/MMBtu	10	LEI assumption, as compared to $9/MMBtu in CFP2019 slide 59

Note: Capital cost estimates for solar and storage are not far off from the assumptions presented in IRP 2019. LEI assumptions are discussed further in Appendix C, Section 12.4.2 and Section 12.4.4.

A comparison of the LCOEs for different illustrative self-supply options against the rates from CFP2019 is presented in Figure 21. Across the evaluated configurations, a 6 MW solar + 1.5 MW battery is the most competitive option, at 27.2 cents/kWh, and is only slightly higher than the rates forecast by PREPA in its CFP2019 in the near term, but will be lower than LEI's forecast of future rates (see Section 7). [137,138] The 2x reciprocating engines solution is the most expensive

[133] National Renewable Energy Laboratory (NREL). *2018 Annual Technology Baseline*. 2018. Golden, CO: National Renewable Energy Laboratory. <http://www.nrel.gov/analysis/data_tech_baseline.html>

[134] NREL. Evaluating the Technical and Economic Performance of PV Plus Storage Power Plants. August 2017.

[135] IRP 2019. Page 6-2 Exhibit 6-1 and Page 6-23 Exhibit 6.32.

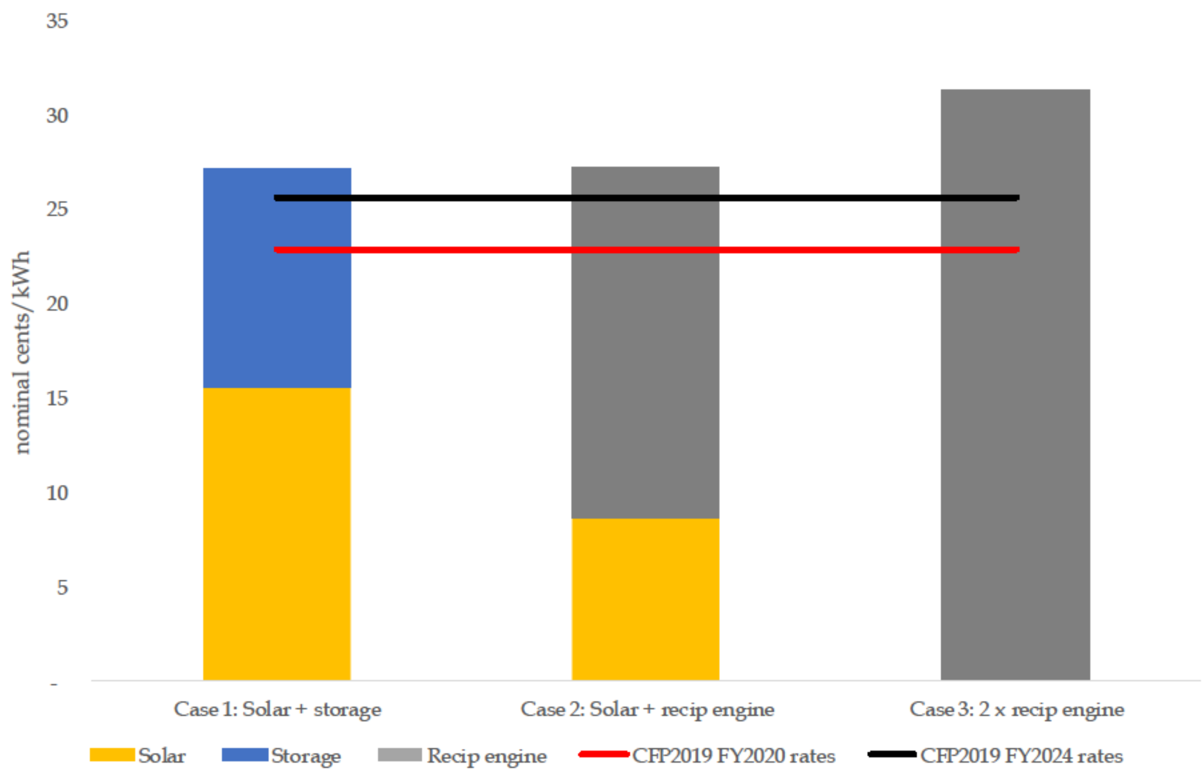
[136] CFP2019 slide 59.

[137] LNG imports in Puerto Rico have recovered following Hurricane Maria; Puerto Rico imported 60.3 billion cubic feet ("BCF") of LNG in 2018, similar to total LNG imports of 61 3 BCF in 2016. (Source: US Energy Information Administration. *Puerto Rico's LNG imports returned to pre-Hurricane Maria levels in late 2018*. April 2019. <https://www.eia.gov/todayinenergy/detail.php?id=38972>

[138] Due to the Jones Act, almost all of Puerto Rico's current LNG demand is satisfied via long-term contracts to import LNG from Trinidad. However, according to PREPA, Puerto Rico has requested a 10-year waiver to the Jones Act to facilitate the import of US LNG. (Source: Mr. Vasquez's written statement before the House Committee on Natural Resources Hearing on the Rebuilding and Privatization of PREPA, April 9, 2019)

alternative presented below, but even this option will become competitive with PREPA's costs of service over time, as indicated in LEI's forecast of future rates.

Figure 21. Illustrative costs of self-supply configurations relative to PREPA's rates



Source for CFP2019 FY 2020 and FY2024 rates: slide 62 in CFP 2019

These results suggest that for industrial, commercial, and high-income residential consumers able to afford the initial capital costs of installation, a self-supply system may be an economically viable alternative to continuing to take electricity from PREPA (and then that customer would be able to avoid the Transition Charge).[139] IRP 2019 projects that there could be 1,176 MW of customer-owned generation systems on the island by 2038.[140] Siemens, the author of the IRP, goes on to conclude that customers may indeed leave the system under certain circumstances, including "if they are able to raise the capital investment required," or if there are alternative financing arrangements (for example "if a developer installs the equipment and recovers the investment through leases or other financing options").[141] LEI employed the findings of IRP 2019 in its rate forecast.

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[139] LEI's results are consistent with Rocky Mountain Institute ("RMI") discussions with developers. Specifically, RMI has indicated in its interviews with developers that it is possible to deploy solar and battery-based microgrids for a cost "between $0.18–$0.24/kWh for remote communities and/or small-scale (<1 MW) systems sited at large businesses." (Source: RMI Brief. *The role of renewable and distributed energy in a resilient and cost-effective energy future for Puerto Rico.* December 2017.)

[140] IRP 2019, Page 244.

[141] Ibid.

6.4 A substantial portion of the residential population may lack ability to pay in full

Another reason that demand for electricity may decrease in Puerto Rico quickly relates to the composition of PREPA's customer demand. A large share (37% in 2018)[142]of the electricity consumed in Puerto Rico is associated with residential customers. In turn, a large segment of households (in this residential customer class) fall into the low-income population bracket. Some of these customers may simply be unable to afford to pay for the electricity as rates rise. Low income[143] households generally spend a larger percentage of their income on energy costs than more affluent households. As a result, collection rates are typically lower for low income households. An increase in PREPA's rates could make electricity unaffordable to a larger number of households, pushing collection rates further down.

6.4.1 Puerto Rico's population faces high energy burden

Electricity costs have historically been high on the island. Using the current electricity rate of 18.8 cents/kWh for the current cost of electricity and 5,585 kWh as the annual average electricity consumption on the island, annual average electricity costs in Puerto Rico total $1,050. In addition, households must also pay for propane or other fuels to heat their homes and to cook food. Estimates for the average annual non-electric utility costs are $739,[144] bringing the total average annual energy cost in Puerto Rico to $1,789.

To determine the energy burden for each income bracket, LEI had to make several simplifying assumptions. First, LEI assumed the highest level of income for each bracket. Second, LEI used the same average annual energy cost for each income bracket, although it is likely that higher income households will use more energy than the average and that the lowest income households will use less. Figure 22 below presents a breakdown of Puerto Rico's income brackets, and corresponding energy burden.

[142] IRP2019 Exhibit 302

[143] The generally accepted definition for low income in the US is households that earn below 150% of the Federal Poverty Guidelines (US Health and Human Services).

[144] Expatistan. "Cost of living in Puerto Rico." <https://www.expatistan.com/cost-of-living/country/puerto-rico>

Figure 22. Comparison of Puerto Rico income breakdown with energy burden

Income breakdown	% of households	# of households	Utility burden by income bracket*	
			At 18.8 cent/kWh	At 22.37 cent/kWh rate**
Less than $10,000	28.50%	348,443	17.9%	19.9%
$10,000 to $14,999	11.80%	144,268	11.9%	13.3%
$15,000 to $24,999	18.20%	222,514	7.2%	8.0%
$25,000 to $34,999	12.10%	147,935	5.1%	5.7%
$35,000 to $49,999	11.50%	140,600	3.6%	4.0%
$50,000 to $74,999	9.70%	118,593	2.4%	2.7%
$75,000 to $99,999	3.90%	47,682	1.8%	2.0%
$100,000 to $149,999	2.70%	33,010	1.2%	1.3%
$150,000 or more	1.60%	19,562	0.9%	1.0%

* Assuming highest level of income for each bracket
** With addition of 3.57 cent/kWh transition charge

Source: US Census Bureau. "American Fact Finder – S1901 – Income in the past 12 months (In 2017 inflation-adjusted dollars)." <https://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?src=CF>

The results demonstrate that the energy burden for Puerto Rico's lowest income households is very high. The distribution of residential customers is expected to follow closely the distribution of income. As such it can be deduced that at the current rate of 18.8 cent/kWh, the energy burden for the 40% of households that earn under $14,999 ranges from 13.5% to 20.5%. These energy burdens clearly exceed the 6% and 10% thresholds commonly applied in the US and the UK to identify households in energy poverty. In addition, the next 18.2% of households, which earn between $15,000 and $24,999, would also be highly sensitive to any increase in electricity rates given that their energy burden stands at 8.2%.

6.4.2 Theft and bad debt may increase if electricity rates increase

The collection of unpaid bills has been a long-standing problem for PREPA. In their most recent monthly statement for July 2019, PREPA had an allowance of $830 million for uncollected accounts.[145] In CFP2019, PREPA noted that it had budgeted a bad debt expense of over $273 million.[146] However, FY 2019 year to date performance suggested some improvement in the situation, noting YTD bad debt expense of only $7 million.[147, 148] LEI therefore did not to include this cost explicitly in its rate forecast. Nonetheless, if collection deteriorates, it would create a rising cost of service for PREPA.

As mentioned in Section 5.1, PREPA also has relatively high level of technical losses and theft. In 2016, PREPA reported a total loss rate of 17.3% per annum,[149] which is more than three times

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145 Puerto Rico Electric Power Authority. *Monthly Report to the Governing Board April 2019.* <https://aeepr.com/es-pr/investors/FinancialInformation/Monthly%20Reports/2019/July%202019.pdf>

146 CFP2019, slide 38.

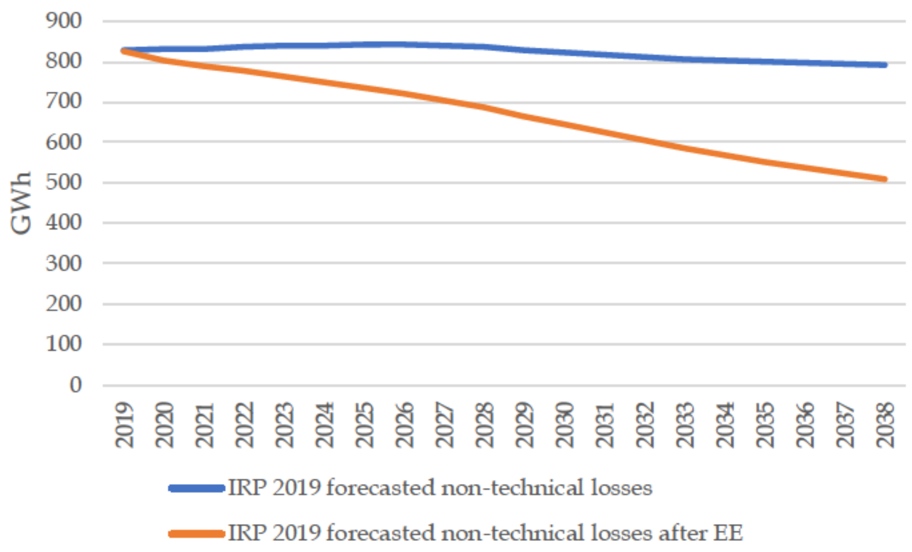
147 Ibid.

148 CFP2019 has assumed a $62 million of bad debt expense from FY 2020 to FY 2024, but did not represent this cost as part of the going forward rates due to its small magnitude (*see* CFP2019, slide 62).

149 Puerto Rico Electric Power Authority. "Amended & Restated Fiscal Plan –Draft" April 5, 2018. Slide 18.

the 2013-2017 US national average of 5%.[150] And this level of non-technical losses is higher than what is observed in other islands (as seen in Figure 11 on page 32). PREPA has been implementing theft-reduction plans since at least 2010, but the rate of theft has increased.[151] IRP 2019 forecasts that non-technical losses will remain at around 800 GWh per annum under the Reference Case from 2019 to 2038, as seen in the figure below.

Figure 23. IRP 2019 forecasted non-technical losses



Source: Siemens. *Puerto Rico Integrated Resource Plan 2018-2019: Prepared for Puerto Rico Electric Power Authority*. Issued June 7, 2019. Report Number: RPT-015-19. P. 57 and 60

In summary, the Transition Charge will further stress vulnerable customers. A 3.57 cents/kWh average Transition Charge over the next 24 years would increase the average annual energy cost in Puerto Rico by 10.3%, or to $2,237 per household (based on typical consumption of 5,859 kWh per year).[152] This is a sizable impact given the average GNP per capita in Puerto Rico (see Figure 12 on page 30). Moreover, non-technical losses are expected to increase as electricity becomes increasingly unaffordable; studies in developing countries have shown that rising electricity rates lead to higher rates of theft.[153] Puerto Rico's most vulnerable households earning under $10,000 per year, would face a two percentage point increase in their energy burden, to 22.4%, as shown in Figure 22. Such an increase in energy burden will likely lead to more bad debt and more theft. CFP2019 suggests that bad debt expense is declining. LEI

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[150] US Energy Information Administration. "Frequently Asked Questions: How much electricity is lost in electricity transmission and distribution in the United States?" Updated January 9, 2019. <https://www.eia.gov/tools/faqs/faq.php?id=105&t=3>

[151] Government Development Bank for Puerto Rico. "PREPA Power Revenue Bonds. Series EEE (Issuer Subsidy Build America Bonds)." <http://www.gdb.pr.gov/investors_resources/documents/2012-06-13-PRElectricPowerAuth08b-FIN-SeriesEEE.pdf> See also footnote 74 on page 32.

[152] Based on the average of the projected transition charge between FY 2021 and FY 2044.

[153] Jamil, Faisal and Eatzaz Admad. *An empirical study of electricity theft from electricity distribution companies in Pakistan.* <http://pide.org.pk/psde/pdf/AGM29/papers/Faisal%20jamil.pdf>

therefore decided not to include a separate analysis around this cost in the rate forecast model. However, LEI did consider how the forecast rates impact theft, as discussed further in Section 13.

6.4.3 Key takeaways regarding future demand for electricity in Puerto Rico

A number of key takeaways are evident from the analysis of the current customer mix and demand drivers into the future.

- **Over time, rate increases will lead to reduced electricity consumption.** Rising rates will motivate customers to seek out alternatives, where they change their consumption profiles through conservation or efficiency initiatives or simply leave the system.

- **DERs will be able to compete with PREPA's rates.** As demonstrated through the grid defection configurations illustrated in Section 6.3.2 above, DERs present a practical and economic case for customers to leave the PREPA system.

- **Wealthier customers are more likely to leave the grid.** Due to the high capital costs of all the self-supply solutions, only wealthier customers may have the means to install their own generation, and defect from the grid. While nearly half of Puerto Rico's GDP comes from the manufacturing/industrial sector, it only accounts for 19% of the labor force. Around 75% of Puerto Rico's labor force is employed in services and trade, which accounts for just over 40% of GDP.[154] Puerto Rico households with an income exceeding $100,000 per year constitute 4.3% of total households.[155] Residential households in lower income households may find it difficult to leave the grid, even if they accept significantly lower levels of reliability.[156]

- **Energy burden may increase, leaving PREPA with a growing "energy poor" customer base that cannot afford to pay for rising costs of service.** Self-supply may lead to an adverse selection problem and contribute to economic problems on the island.

- Even if PREPA moves to use more renewable technology (including DERs), **its rates would include balancing costs from old fossil plants plus wires charges.** The LCOE and rates comparison shown in these scenarios do not account for the fact that even if PREPA were to finance and install DERs, the rates charged for supply from the grid would need to include balancing costs, return on and off capital previously invested, as well as various operations and maintenance costs.

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[154] Santander Bank. Trade Portal. *Puerto Rican Economic Outline*. Last updated July 2019. <https://en.portal.santandertrade.com/analyse-markets/puerto-rico/economic-outline>

[155] US Census Bureau. "American Fact Finder – S1901 – Income in the past 12 months (In 2017 inflation-adjusted dollars)." Figure 21. <https://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?src=CF>

[156] PREPA's customers already experience much worse levels of reliability relative to peer group utilities in the US. Considering standard reliability metrics such as SAIFI (average number of outages per customer) and SAIDI (average length of outages per customer), PREPA customers experienced nearly 5 outages on average, and 14.4 hours of outages on average, relative to the US median of 1.04 and 1.92, respectively. (Source: PREPA. *Puerto Rico Electric Power Authority: Fiscal Plan*. August 1, 2018.)

6.5 Rising energy burden may lead to larger (economy-wide) problems

Negative load growth can be a self-reinforcing problem for utilities, where the loss of customers simply increases the rate that remaining customers have to pay (because the costs are spread over a smaller volume), and that slowly serves as an economic incentive for the remaining customers to seek alternative options. In addition, if businesses cannot fully pass on the increase in electricity rates to consumers, then their profit margin would decrease, leading to further deterioration in the economy. Mr. Brownstein authored a declaration in support of approval of the Definitive RSA, dated July 2, 2019 (referred to herein as the "Brownstein Declaration"),[157] in which he recognized that there was an important linkage between a financially viable utility and the greater economy. In fact, he identified a number of economic goals that were paramount to Government Parties' evaluation of the RSA, including specifically the prioritization of the "Commonwealth's overall economic recovery" and "fostering a healthy economic outlook for the future of the utility".[158]

When forecasted demand decreases over time, the costs required for PREPA to provide its services do not drop at the same rate. For example, some existing generating assets will continue to be maintained to meet reserve requirement as renewable energy deployment increase. The cost of investing in, and then maintaining, the transmission and distribution system will also not vary with the volume of electricity service taken by customers. Once investments have been made, they need to be recouped over time. O&M costs are also difficult to reduce over time, without sacrificing the quality of service. Reduction in maintenance spending could decrease the reliability of the grid. Even if labor costs can be reduced, pension obligations are not related to volume of electricity sold by PREPA. With sales volume declining faster than total cost required to serve customers, the cents/kWh rate would have to increase. This would further increase the financial burden on customers and potentially endanger the financial viability of the utility. While a complete "utility death spiral" have yet to be experienced in the US electricity sector, PREPA is "at risk."

Some stakeholders have commented that the non-bypassable feature of the Definitive RSA could potentially discourage the development of BTMG systems and other customer-initiated distributed generation investment activities.[159] On the other hand, the nature of a non-bypassable Transition Charge will also reinforce and strengthen an adverse-selection problem for PREPA's customer mix. Wealthier customers who can afford the BTMG systems and can fund the investments needed to disconnect completely from the PREPA system[160] will exit PREPA's franchise, leaving PREPA with the economically challenged customers, who are also at a higher risk for non-payment. In a service territory like Puerto Rico, these concerns are heightened as there are many residential customers that are already facing challenging levels of

[157] Declaration of David Brownstein in Support of Joint Motion of Puerto Rico Electric Power Authority and AAFAF Pursuant to Bankruptcy Code Sections 362, 502, 922, And 928, And Bankruptcy Rules 3012(A)(1) And 9019 For Order Approving Settlements Embodied in the Restructuring Support Agreement. July 2, 2019.

[158] Brownstein Declaration, paragraph 25 and 27.

[159] Center for a New Economy. PREPA Debt Restructuring 3.0: It is Even Worse Than You Think. May 2019. Page 8.

[160] Ibid.

energy burden, as discussed above. Private investors and more generally capital markets may be averse to lending money to PREPA if such adverse selection problems arise.[161] This can have grave consequences for PREPA's plans for Transformation.

If the electricity sector is not able to provide reasonably priced service to customers, that may then undermine the larger economy. Andrew Wolfe, advisor to the FOMB, noted in 2017 that a rate increase above a certain threshold "would greatly increase the risk of reducing economic growth below the minimum amount of real economic growth necessary for Puerto Rico to achieve fiscal and debt sustainability."[162] Although much has occurred since Mr. Wolfe prepared his analysis – including the devastating destruction of the power system as a result of two hurricanes and a prolonged power outage and economic crisis – the basic concepts underpinning Mr. Wolfe's concerns continue to hold (though the actual numbers may differ). As Mr. Wolfe laid out in his expert opinion, rising electricity rates can hamper economic growth (especially given the competition for manufacturing and tourism dollars from neighboring jurisdictions), and Puerto Rico needs to experience real economic growth in order to get to a point of sustainability with its fiscal policies.[163] Therefore, the trajectory of electricity rates is of vital importance to get Puerto Rico's economy back on track.

[161] In some cases, when private investors were dissuaded from serving a specific segment of the market, adverse selection problems have led to "missing markets." For example, in the insurance sector, private insurance firms have exited some segments of the market because they do not find it profitable to sell their services. This has required governments to step in to provide services for uninsurable customers.

[162] *See* Declaration of Andrew Wolfe in Support of Opposition of the Financial Oversight and Management Board for Puerto Rico to the Motion of the Ad Hoc Group of PREPA Bond holders, National Public Finance Guaranty Municipal Corp., Assured Guaranty Corp., Assured Guaranty Municipal Corp., and Syncora Guarantee Inc. for the Relief from the Automatic Stay to Allow Movants to Enforce their Statutory Right to Have a Receiver Appointed. Paragraph 11, Page 6. ("Wolfe Declaration").

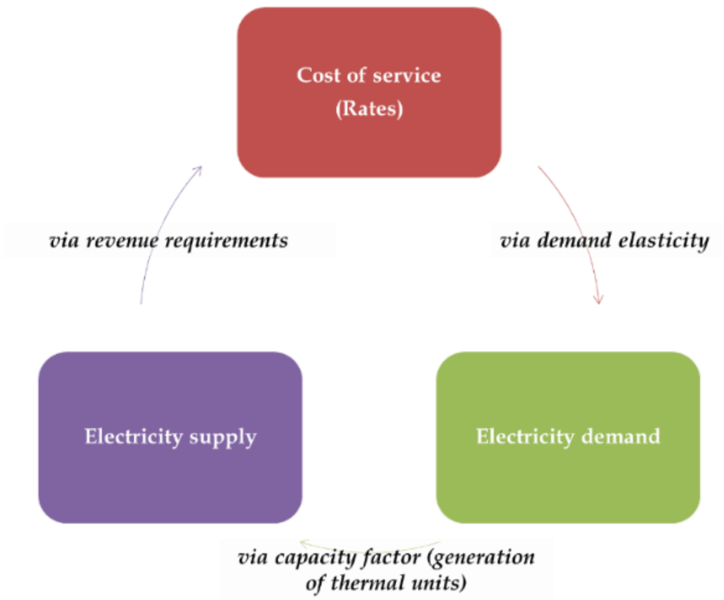
[163] Paragraph 52 and 53 of the Wolfe Declaration.

7 Implications for the Definitive RSA from evaluation of PREPA's future rates

LEI developed a long-range rate forecast for PREPA.[164] Note that the purpose of the rate forecast is not *per se* to present projected rates, but rather to study how future costs for PREPA's services, with the Transition Charge, will affect consumers' electricity consumption patterns, so that we can better understand the impact that the Definitive RSA may have on electricity sector demand as well as the long term sustainability of the utility business. While this section of the Report provides an overview to that methodology and its underlying assumptions, more details on LEI's forecast of the revenue requirements and electricity demand are provided in the Appendices.

As discussed in Section 3, there are two critical components to a utility rate forecast: a projection of the cost of service for the utility (which is commonly referred to as a revenue requirement) and a projection of the units of service consumed or billing determinants (which in the case of PREPA's services would be measured in terms of kWh of electricity sold). The rate for electricity service is the annual cost of service divided by the total volume of energy consumed in that year. As contemplated by the RSA, the Transition Charge is added on top of the resulting rate. Therefore, if the Definitive RSA is approved, customers will have to pay an all-in rate that reflects the cost of service plus the Transition Charge. A diagram illustrating LEI's modeling is presented in the figure below.

Figure 24. Integrated nature of LEI's rate forecast



[164] LEI's modeling horizon is from FY2020 to FY2047. Although the Securitization Bonds will have a maximum term of 47 years from effective date (i.e. ending notionally in FY 2069), LEI forecast future rates only through FY 2047. This timeframe is sufficient to understand the long term impacts of the Definitive RSA on PREPA's rates and electricity demand. In addition, LEI notes that because the Transition Charge will be capped after FY 2044; LEI extended the model three additional years beyond this point to demonstrate the trend.

LEI's bottom-up forecast of the revenue requirement follows four key principles:

- PREPA's rates will need to cover **the full costs of service** in order to move towards a reliable and sustainable business model. As such, capital investments, unless funded with Federal grants or subsidies, will need to be recouped over time through rates.

- The cost of service should be based on a **holistic assessment of capital investment needs** (generation and T&D): generation investments cannot occur in a vacuum. High levels of renewable integration will require additional T&D investment.[165]

- The **costs of service have to align with electricity demand levels**, while considering variable versus fixed nature of different costs. For example, if electricity demand is rising, more investment may be needed in generation and/or transmission. On the other hand, if in the future, electricity demand falls, variable costs of operation should follow suit (e.g., less fuel will be burned). However, fixed costs may not be able to be reduced proportionally. In fact, previously incurred investment costs, would not be avoidable simply because demand levels are lower.

- It is imperative to consider **how consumers will respond to the rates** that they will be charged based on these costs of service. Economic theory posits that rising prices should motivate consumers to reduce their demand for a product. As such, rising rates for electricity service should reduce future electricity consumption. This phenomenon is not simply theoretical – there is significant empirical research on this subject matter. LEI therefore considers how PREPA's customers will react to the trajectory in rates over time. Consumer response is fed back into the electricity demand projections, which in turn impacts costs of service and resulting rates, providing for a dynamic and internally consistent rate forecast.

Thus, LEI began its rate forecast by developing a projection of the cost of service for PREPA. LEI's forecasted cost of service reflects the current operating costs plus changes over time to accommodate the Transformation, legislative policies, inflation pressures on costs, potential efficiency gains, and electricity consumption patterns of PREPA's customers. To complement the cost of service, LEI also developed an electricity demand forecast that considers the price elasticity of demand and the feedback effects between electricity demand from commercial and industrial customers and overall economic activity. There are several linkages between the costs of service and electricity demand. For example, electricity demand (peak and annual total consumption) affects costs of service, as it drives the need for investment in generation (to expand energy production) and associated T&D (to deliver that energy). At the same time, the

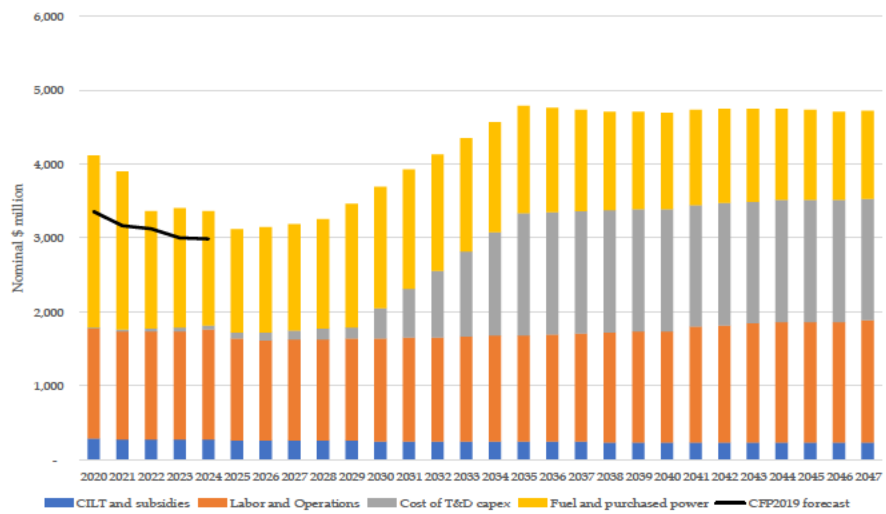
[165] In recognition of the fact that renewable generation integration will require significantly more T&D and generation investment over the longer term than contemplated in PREPA's short term Fiscal Plans, and therefore potentially increase the rate burden on PREPA's customers, LEI decelerated the ambitious pace of renewable buildout in legislation. Please see Section 12.4.3 for further discussion.

trajectory of costs of services also impacts the total volume of energy consumed, as customers seek out ways to reduce their consumption of electricity[166] when faced with rising rates.

7.1 Cost of utility service will rise in the longer term

In LEI's forecast, PREPA's cost of service will start at $4,104 million a year (in FY 2020)[167,168] and rise to over $4,726 million a year by FY 2047 (in nominal terms), as seen in the figure below. Although the costs of service decline in the first decade of the forecast timeframe due to reduced use of fossil fuels and efficiency gains in operations, eventually, the costs of service rise again.[169] The increase in the costs of service is primarily due to the additional costs associated with T&D capital investments that ratepayers will need to pay for, once Federal funding is exhausted. Appendix C (Section 12 of this Report) provides a detailed description of each category of costs in the revenue requirement.

Figure 25. Projected revenue requirement for PREPA under LEI's Base Case



Source: The stacked bars represent the forecast in LEI's rate model; the black line reflects the projections in CFP2019.

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[166] LEI uses the terms "energy" and "electricity" interchangeably in this Report.

[167] LEI's forecast is higher than CFP2019's forecast by $747 million in FY 2020, mainly because LEI included pension liabilities of $222 million in LEI's FY2020 forecast while CFP2019's FY 2020 forecast does not have pension liabilities included that year. LEI included this pension liability in FY 2020 based on the data in slide 87 of CFP2019. Also, LEI forecasted a higher fuel cost by $221 million as compared to the $1,140 million forecasted in CFP2019 as LEI does not expect new renewables to be commissioned in FY2020. Another material difference for FY2020 is the cost of inefficiency dispatch of $230 million (based on relationship between non-ideal dispatch cost in slide 66 of CFP2019 times demand in CFP2019's projected FY2020 and non-renewable fuel cost in slide 69 of CFP2019).

[168] LEI's forecast for FY 2024 is $153 million higher than CFP2019's forecast for that year, primarily due to inclusion of compensation for concessionaire and projection of capex for existing generation (neither of these costs appear to have been included in CFP2019). The difference between LEI and CFP2019 is lower in FY 2024 than FY 2020 because (1) by FY 2024 LEI has estimated lower fuel and purchased power than CFP2019 due to lower forecasted demand and (2) LEI has slightly larger productivity gains related to T&D and generation O&M costs as compared to CFP2019.

[169] The fuel and purchased power category of costs reflects both the fuel purchases for PREPA's existing generation and the annual costs of the PPOAs (existing PPOAs and also new PPOAs that PREPA would enter into with third-party generation owners in the future).

LEI's base case revenue requirement forecast is conservative for a number of reasons:

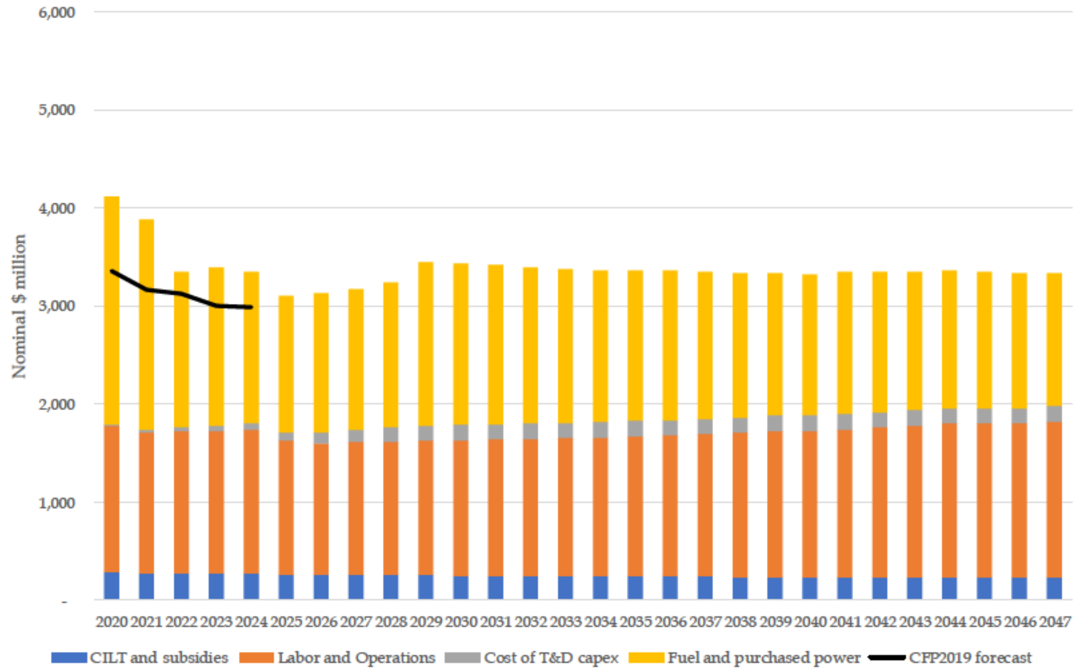
- LEI has higher levels of year-over-year cost reductions (operating efficiency gains) in the short term as compared to the assumptions in CFP2019;
- LEI has assumed that population trends will stabilize (e.g., no further declines) after 2038;
- LEI has calibrated the amount of generation investment needed to the load forecast; lower levels of demand growth require lower levels of generation investment which is less costly for the overall system;
- LEI has continued PREPA's optimistic assumptions from CFP2019 that 90% of its T&D investments over the next 10 years would be funded by Federal funds, although that is very uncertain;[170]
- LEI has deferred the renewable generation targets in order to slow down the rate increases that would have otherwise been incurred due to higher PPOA costs and larger T&D capital investment associated with integrating more renewables;
- LEI has used a very conservative estimate of future T&D investments, limiting total capital spend for the T&D network to $30 billion over the forecast timeframe (although Puerto Rico's COR3 has suggested that as much as $90 billion may be needed, as discussed in Section 12.3);
- LEI has not incorporated any management fee or profit margin for the operators of PREPA's existing generation assets as that would have otherwise required further rate increases); and
- LEI has capped compensation to the T&D concessionaire on the basis of the net present value ("NPV") of the 20-year contract rate to be paid equally over 20 years, which means that the T&D concessionaire's compensation is growing at a smaller pace than the T&D system.

LEI also tested an alternative outlook for future costs (the "Alternative Case"), where future T&D investment was limited. Specifically, LEI assumed that total capital spend over the entire modeling timeframe would not exceed $16.4 billion, and that would be 90% funded by the Federal government. LEI's Alternative Case proxies for a world where PREPA's "central utility" business model evolves into a "DER-focused" business model and therefore additional

[170] LEI assumed that $1.95 billion has already been provided by the Federal government, and the remainder of the $16.4 billion required to modernize and rebuild the grid over the next 10 years would be funded 90% by the Federal government. Notably, the uncertainty around the availability of external funds for T&D investment is a recognized risk in the CFP2019. In addition, the RFQ for the transmission concessionaire issued by P3 Authority also noted that Federal funds "will be available to ***partially*** finance the restoration" (see page 14 of the RFQ, attached as Exhibit A to Declaration of Frederic Chapados).

spending on T&D would be deemed unnecessary. The Alternative Case retains all other assumptions from LEI's Base Case.[171]

Figure 26. Projected revenue requirement for PREPA under LEI's Alternative Case



Source: The stacked bars represent the forecast in LEI's rate model Alternative Case; the black line reflects the projections in CFP2019.

Impact of renewable target dates

In LEI's rate forecast, it was assumed that the renewable target would be delayed by 10 years, as LEI expects that PREPA's financial and technical obstacles in the near term to will prevent them from meeting the 40% renewable target by 2025.

However, if the target dates stipulated in Act 17-2019 are achieved, it will result in higher overall rates in both the near term and the longer term. For the near term, the cost increase would be driven by the capital investment needed to support more renewables and peaking resources to meet the reserve requirement. In addition, more T&D investment would be needed to support renewable expansion. At the minimum, the $30 billion investment LEI assumed for long run T&D would need to be accelerated. However, COR3 has acknowledged that this amount may not be enough to meet 40%-50% renewable target. For every additional $10 billion of T&D investment, the annual costs of service will rise by $193 million by year, increasing annual rates by 5% to 45%, depending on the timeframe (if investments are required early, it will create a more severe rate increase and quicken the vicious cycle involving customer defection from the grid and rising rates for remaining customers).

[171] And, implicitly, this Alternative Case also assumes that solar PV DG resources would achieve cost parity with utility-scale solar PV within the next ten years.

7.2 Volume of electricity sold by PREPA will decline

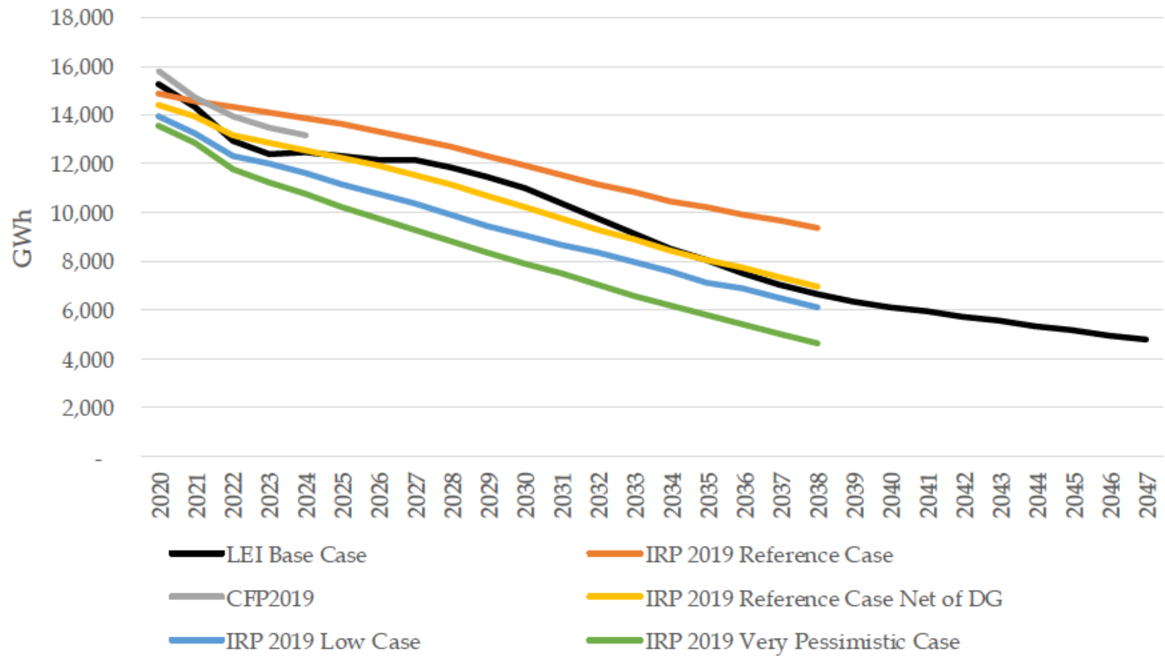
LEI's demand forecast is keyed off the same starting levels as CFP2019 and IRP 2019 (namely FY 2019) estimated demand by customer class, and the population and GDP forecasts assumed in CFP2019. However, LEI also considered the feedback effect related to rising rates and how reduced electricity consumption may affect GDP. A more detailed description of LEI's energy demand forecast is presented in Appendix D (Section 13).

Change in demand in response to prices and incentives can take several forms: (1) installation of distributed generation (customer-owned generation). The IRP 2019 had projected certain levels of CHP and solar DG (although it appears that CFP2019 did not consider those demand offsets); (2) customers can also be motivated, with incentives, to be more efficient in their energy use (this is the goal of the various energy efficiency programs identified in the IRP 2019); and (3) other possible responses to higher costs – for example, customers can also conserve energy or modify how and when they consume energy and they can choose to invest in appliances (and business processes) that are more efficient. In developing this demand forecast model, LEI took steps to ensure there was no double-counting of different drivers affecting electricity demand. LEI used Siemens' forecast of energy efficiency programs as an input. [172] LEI also capped the level of distributed generation and customer owned generation by the amount forecasted by Siemens. For the remaining demand forecast not impacted by these two channels, LEI applied a conservative, empirically derived long-run demand elasticity factor for each customer class to the annual demand projections.

Even with the application of long run price elasticity of demand, LEI's Base Case electricity demand forecast is not too far off from the "Low Case" presented in IRP 2019 (as seen in Figure 27 below). And notably, LEI's Base Case forecast is on average 30% higher than the "Very Pessimistic Case" in IRP 2019.

[172] The level of residential customer demand exposed to price elasticity of demand in Lei's forecast is set after netting out the amount of energy efficiency achieved for the residential customer sector, as forecast by Siemens in IRP 2019. This ensures that residential customers who are projected to participate in the utility-sponsored energy efficiency programs are not included in the residential load to which LEI applied the long run elasticity of demand. In other words, LEI assumed that these residential customers would not seek out additional opportunities to further lower their demand over the study timeframe.

Figure 27. Comparison of LEI's electricity demand forecast under the Base Case with IRP 2019 and CFP2019

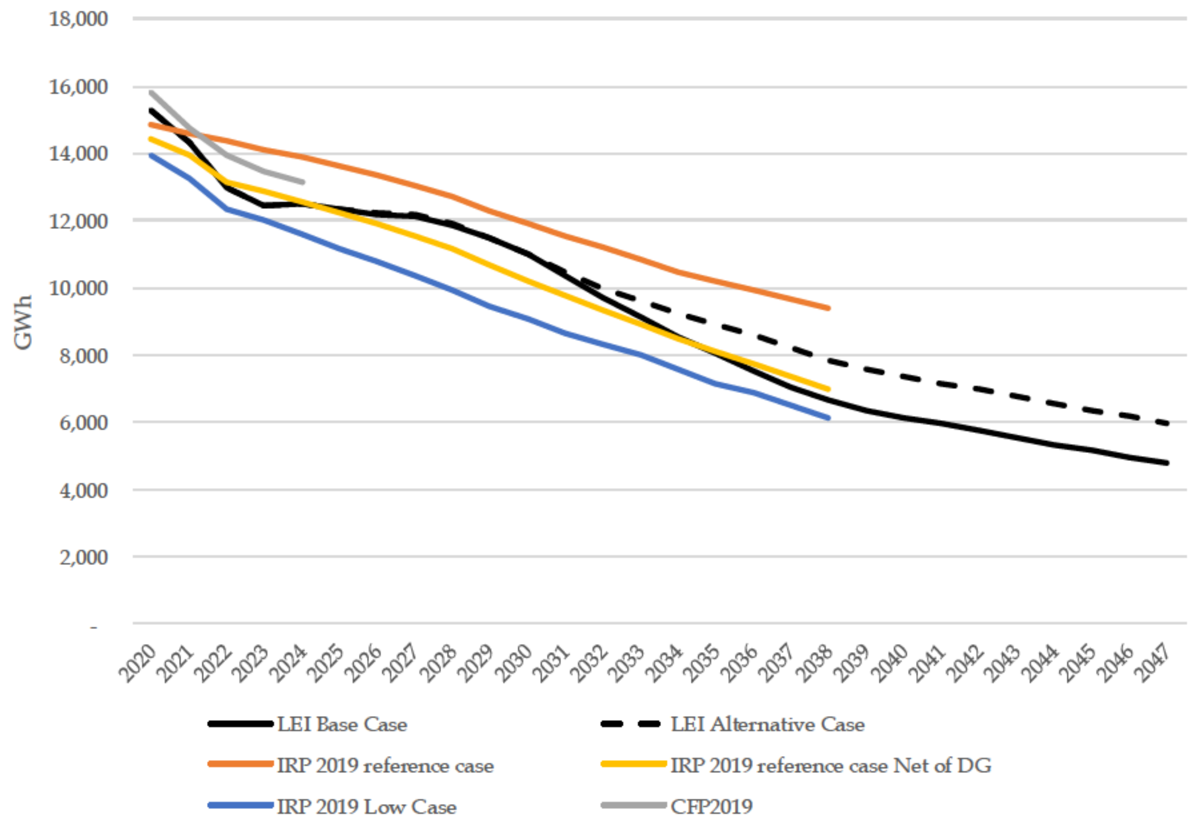


Source: LEI, IRP 2019, CFP2019

Note: LEI's demand forecast starts at the same level as CFP2019 for FY 2019, but then deviate in FY 2020 as LEI begins to add in energy efficiency and distributed generation based on IRP 2019 forecasts, which could be different from CFP2019 projections. Over the longer term, the addition of the demand elasticity also contributes to a more dynamic trend in LEI's forecast.

Due to the lower forecasted total cost in the Alternative Case, the elasticity of demand effect is smaller under LEI's Alternative Case as compared to the Base Case. The resultant demand forecast under the Alternative Case is on average 15% higher than the Base Case from FY 2030 to FY 2047 and stays above the IRP 2019 reference case Net of DG for many years (see Figure 28 below).

Figure 28. LEI's electricity demand forecast under the Base Case and Alternative Case



7.3 Aggregate impact of declining load and increasing costs on PREPA's rates

The previous subsections outlined the impacts that the various policy, regulatory and business drivers will have on PREPA rates. LEI's analysis is intended to study how these future costs, including the Transition Charge, affect consumers' consumption patterns. The Transition Charge is anticipated to be a direct component of the rates that PREPA's customers will see and pay. Therefore, in order to understand the reasonableness of the Definitive RSA and the "affordability" of the Transition Charge, it is important to understand the linkages between future rates and customers' behavior (demand for electricity from the utility). LEI's analysis suggests that the Transition Charge aggravates the potential problems that are expected to arise around the going forward viability of PREPA's utility business in Puerto Rico because of customers' response to the overall rates.

PREPA rates are constructed as an allocation of the revenue requirement to all PREPA billable load. Hence, if the cost to provide regulated service is mostly fixed (especially in the long run, where fossil fuel use is minimal), and load is decreasing, the rate, in cents/kWh, will have to increase. As a result of the projected trends in cost of service and electricity demand, and in consideration of the additional Transition Charge, LEI projects that the average all-in rate under the Base Case is expected to double by FY 2034 from current levels (see Figure 29), and in real-terms exceed the highest rates of any other privately-operated electricity system in the Caribbean (which is visible in the graphic in Figure 30 on page 63).

Before including Transition Charge, LEI anticipates that PREPA's rates will need to rise to an average of 26.7 cent/kWh (in near term, from 2020 to 2024) as compared to the CFP2019 forecasted average rate of only 21.9 cents/kWh from FY 2020 to FY 2024. Under the Base Case, over the long term, the Base Case forecast of PREPA's rate would have to increase to over 60 cents/kWh by FY 2036 (in nominal terms) and even higher in the longer term. This implies an average annual growth rate of 4.8% from 2020 to 2047 for the Base Case assumptions (notably, this is not a linear trend; the annual growth rate is higher after 2029, at 6.7% per year, because of the burden for funding incremental T&D investments).[173] Under the Alternative Case, LEI forecasts PREPA's rates rising to 53 cents/kWh by FY 2047 (in nominal terms); this implies a growth rate of 2.6% per annum from 2020 to 2047.

The cost of T&D investment has the biggest impact on rates in LEI's Base Case – funding of T&D investment as a percentage of the total annual cost increases from 4% in 2020 to 35% in 2047. The cost of labor and operations increase from FY 2034 to FY 2043 by 12%, while the cost of fuel and purchased power decrease by 16% for the same period, due to phasing out of fossil fuel generation to renewables and decrease in demand.

Once accounting for the Transition Charge, re-estimating the full cost of service (with the Transition Charge), and taking into account demand response to the all-in rates, LEI believes that the final PREPA rate will end up in the range of 27.8 to 30.0 cents per kWh in nominal terms over the next five years. All-in rates under LEI's Base Case will then rise to over 103 cents/kWh over the next 24 years (by FY 2047), which is equivalent to over 65 cents/kWh in 2019-dollar terms. Under the Alternative Case, rates will rise to 60 cents/kWh by FY 2047, or 38 cents/kWh in 2019-dollar terms. As can be seen in the figure above, the Transition Charge will increase the rate burden on electricity customers in Puerto Rico. The Transition Charge stipulated in the Definitive RSA will have a direct impact on the all-in rates that customers face. Indirectly, it will also contribute to lower electricity consumption.

[173] If more transmission investments are needed, or there is less Federal funding available, then for every additional $1 billion that needs to be paid for by customers after FY 2024, rates will need to rise by an additional 3.6% on average over the forecasted period.

Figure 29. LEI Base and Alternative Cases forecasted rate for PREPA's services, including and excluding the Transition Charge (nominal and real dollar terms, cents/kWh)

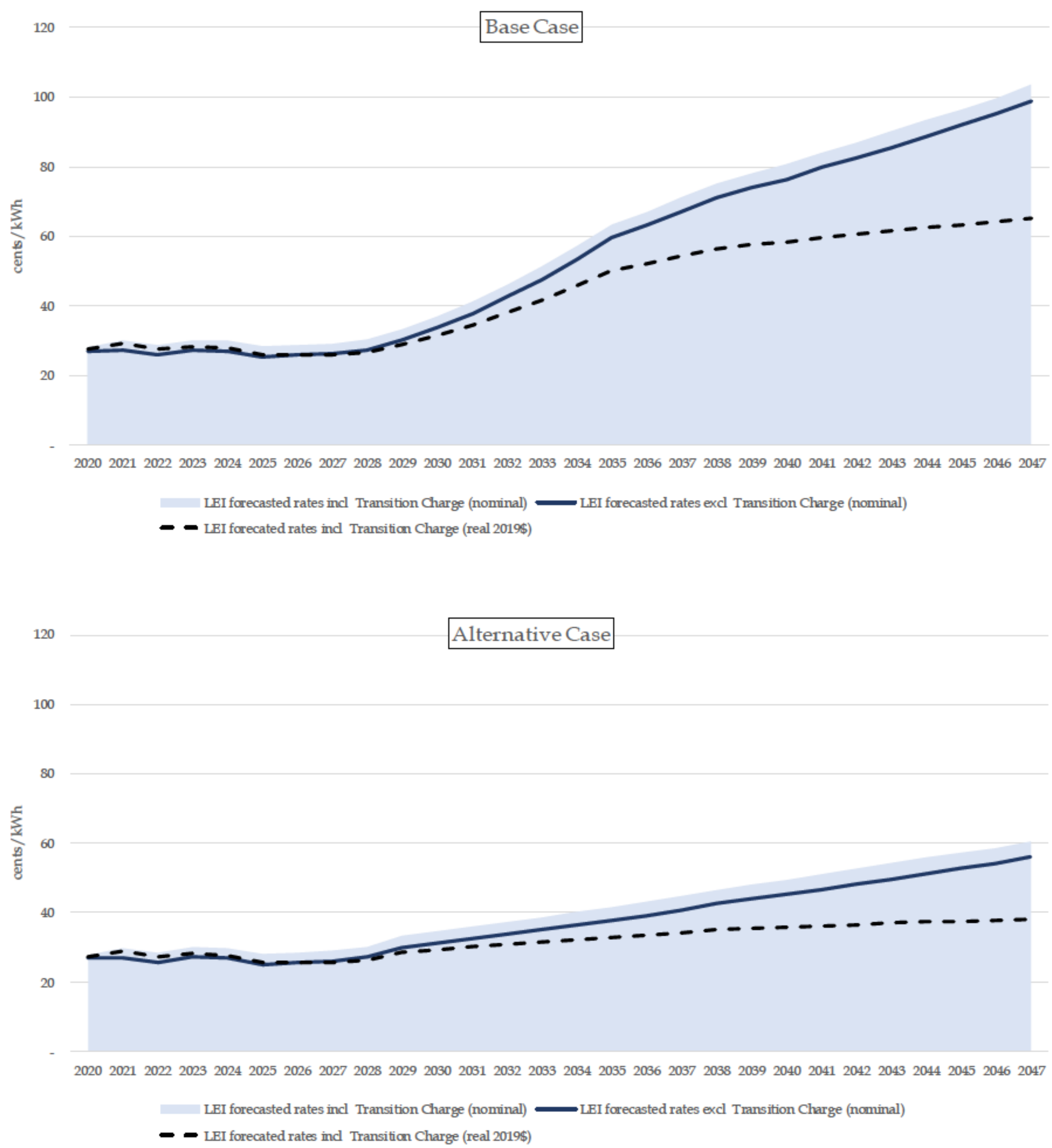
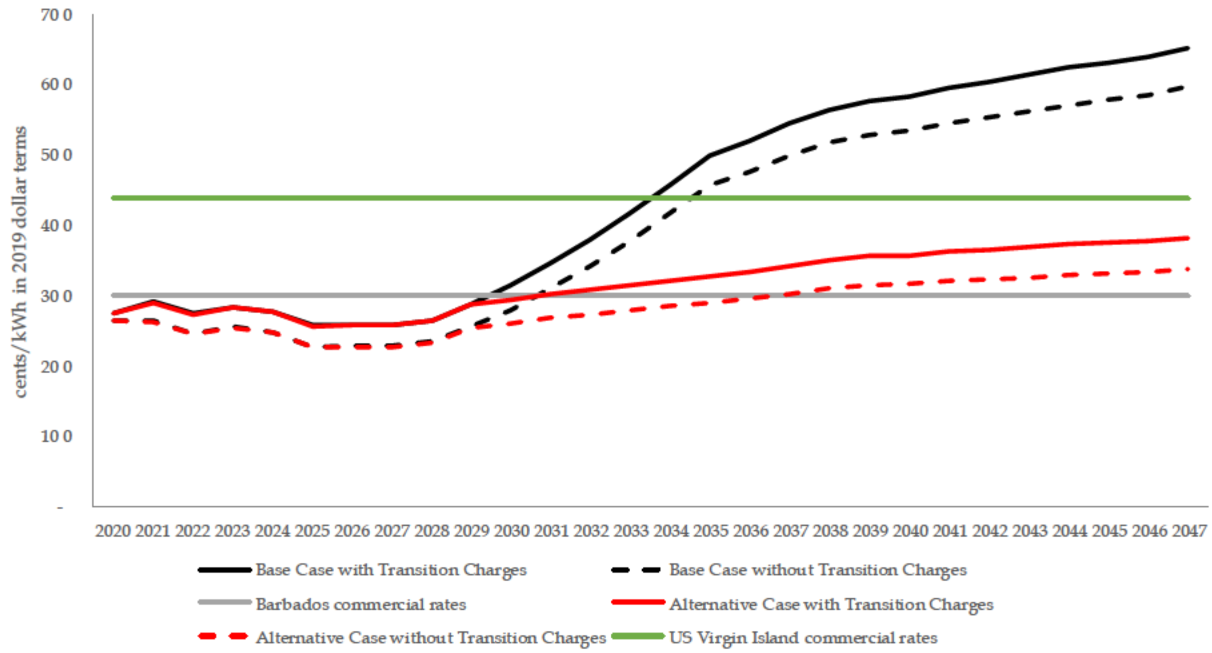


Figure 30 presents the forecasted rates with and without the Settlement and Transition Charge stipulated in the Definitive RSA in real dollar terms under the Base Case and the Alternative Case. Note that the gap between the forecasted rates with and without the Transition Charge increases over the modeling timeframe. This is due to two factors. First, the Transition Charge is designed to grow at above 2.5% per year after 2030, which is higher than LEI's inflation

assumption of 2% and FOMB's 2019 inflation forecast,[174] which means that the Transition Charge is expected to rise more quickly than inflation in the long-run. Second, the forecasted demand is lower due to the existence of the Transition Charge, as consumers' aggregate demand for electricity from the grid will be affected by the rate level. While a lower demand would result in lower variable costs of operation, this reduction in a segment of total costs of service are not large enough to offset the further increase in rates.

Figure 30. Long run forecasted electricity rates for PREPA with and without the Transition Charge (in 2019-dollar terms) compared against current electricity rates in other Caribbean islands



Note: Barbados and US Virgin Island are chosen as comparison jurisdictions as they represent the high and low range of island-based electricity rates.

Figure 30 above also presents LEI's Base Case and Alternative Case forecasts of PREPA's rates against a range of current rates at other Caribbean islands. Notably, PREPA's future rates, in real (2019) dollar terms, will grow to exceed the highest rate of the islands surveyed. This suggests a significant loss of comparative advantage against those other islands' economies. The Base Case forecast rate for PREPA with the Transition Charge would become higher than Barbados' rates before FY 2030, while without the Transition Charge, PREPA's rate will only become higher than those in Barbados after FY 2031. Holding other factors constant, the Transition Charge accelerates the timing of when Puerto Rico's electricity rates may become less competitive than other Caribbean islands.

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[174] Financial Oversight and Management Board for Puerto Rico. *2019 Fiscal Plan for Puerto Rico*. May 9, 2019. Page 43 Exhibit 22. The FOMB has a forecasted inflation rate of 1.4% in 2029, 1.6% in 2034, and 2% after 2039.

Given that the Transition Charge is unavoidable, if PREPA determines that customers cannot afford to pay the final rates, it will need to make other adjustments in its costs of service – perhaps deferring capital spending or cutting O&M spending. Such strategies may help in the short-term but may have grave consequences in the longer term, such as deterioration in the quality of service. High electricity rates, coupled with poor service quality, will only drive other customers off the system. In this way, the Transition Charge may negatively impact the financial viability of PREPA in the longer term.

7.4 Response to the evidence provided by the FOMB's financial advisors

David Brownstein, as head of Municipal Banking at Citigroup Global Markets Inc., led the team that advised the FOMB in the structuring of the Definitive RSA (and he also identified himself as the lead negotiator in PREPA's debt settlement, on behalf of the FOMB). One of the key objectives behind the design of the Definitive RSA, as described in the Brownstein Declaration, was to support the "overall economic recovery" of Puerto Rico.[175] Other objectives related to protection of PREPA's customers and the financial sustainability of PREPA as a viable utility business. In LEI's views, the Definitive RSA has not met these objectives. The Transition Charge, as discussed above, raises the overall rates that customers will need to pay, and thereby accelerates and exacerbates the rate burden on customers and increases the possibility of another financial crisis for PREPA in the future. Based on LEI's analysis of future costs of service if the Definitive RSA is implemented, PREPA will likely find itself in a position where it may need to make difficult decisions with regards to meeting critical policies and "Transformation" goals, because any headroom for rate increases will have been exhausted by the Transition Charge. This is counter to another key objective of the Definitive RSA which is to ensure the viability of the Transformation.[176]

Mr. Brownstein has not shown that the Transition Charge is reasonable. Although he discusses the fact that customers will "know" the magnitude of the Transition Charge (i.e., it will be a "capped charge"[177]), that knowledge does not create any material benefit for customers or PREPA. No one can dispute that the Transition Charge is intended to raise the all-in costs that customers would otherwise face without the legacy debt. Although the new securities do not require a rate covenant, that is not a genuine "benefit" to customers, given that customers must pay the Transition Charge, regardless of what PREPA decides to do with base rates and the quality of service it provides customers. Critically, neither PREPA nor an eventual court administering a subsequent Title III case for PREPA will have any ability to defray, decrease, or otherwise modify the Transition Charge, which will last for decades. As such, if PREPA is to maintain its mandate to charge rates on a full cost of service basis, then it will have no choice but to raise its base rates from time to time in order to both pay for its costs and meet its obligations to legacy bondholders under the Definitive RSA, regardless of whether customers can afford such rate increases. If PREPA fails to raise rates, when it would otherwise need to, then PREPA's customers may lose out due to the need to defer capital investment or cut

[175] Brownstein Declaration, paragraph 25.

[176] Brownstein Declaration, paragraph 29.

[177] Brownstein Declaration, paragraph 41.

operating costs to stay financially viable, leading to a lower quality of service. The owners of the new securities will still get paid, regardless.

Mr. Brownstein also argues that the increase in rates is lower than what it may otherwise be. However, he chooses, as his counterfactual, a state of the world where PREPA's rates would reflect the full amount of the legacy debt. Given what we know about PREPA's current circumstances and prognosis for the future, it is unrealistic to presume that PREPA could increase its rates to repay the full value of the legacy debt. As such, the "savings" to PREPA (and its customers) that Mr. Brownstein estimates are over-stated.[178] In addition, Mr. Brownstein fails to acknowledge that customers, when faced with rising rates, will seek alternatives to PREPA's services and reduce their consumption of electricity from the grid. Mr. Brownstein tries to argue that the Definitive RSA will "protect ratepayers in the event of reduced demand"[179], but this is an incomplete representation of what happens when there is a reduction in electricity demand. A loss of customers will increase the rate burden on remaining customers. So, although the value of the Transition Charge will not change, the presence of the Transition Charge, in and of itself, will contribute to customer defection from the PREPA system, leaving only the customers that cannot afford to leave the PREPA service franchise; those are the customers that are least likely to be able to afford to pay for the rising electricity rates.

In summary, the Transition Charge will exacerbate and accelerate rate pressures, which may have grave consequences for PREPA. LEI's analysis demonstrates that the Definitive RSA may not meet some of "critical economic goals" of the Definitive RSA as posited by supporting parties of the Definitive RSA.[180] Such a negative outlook also leaves no "room" for rates to increase to afford recovery of other liabilities, as discussed in the next section of this Report.

[178] Brownstein Declaration, paragraphs 39 and 40.

[179] Brownstein Declaration, paragraph 46.

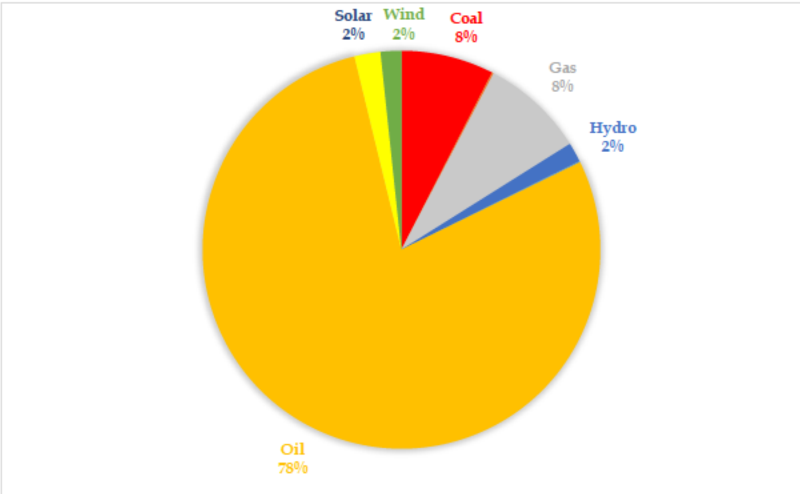
[180] *See* Brownstein Declaration, page 10-11.

8 Value of PREPA's existing generation assets

As part of the Transformation, PREPA is proposing to hire private third-party operators for its existing generation in the future. Outright sale of the existing generation assets is not discussed in CFP2019, but it is conceivable that such a sale could occur.[181] Whether such a sale would create additional value to creditors is questionable. Such a thesis rests on the premise that there will be buyers for the privatized assets that would be willing to pay in excess of the income generating potential of the assets in question.

PREPA currently owns approximately 6,000 MW, composed primarily of fossil fuel fired generation, as shown in the chart below. Approximately 80% of PREPA's existing generation assets, in capacity terms, is oil-fired. Oil is a costly commodity in Puerto Rico as it has to be imported. The use of fuel oil (residual and distillate/diesel) contributes to the high fuel costs of PREPA's generation, and therefore makes it costly to operate relative to other alternatives, such as renewables.

Figure 31. PREPA's existing capacity by fuel type



Note: PREPA also owns negligible amounts of landfill gas and diesel gensets.

Source: Siemens. *Puerto Rico Integrated Resource Plan 2018-2019: Prepared for Puerto Rico Electric Power Authority*. Issued June 7, 2019. Report Number: RPT-015-19. Exhibit 4-1, 4-2, and 4-5.

As seen in the figure below, the average age of the assets is 40 years (in capacity-weighted terms), with some of the oldest capacity approaching 60 years as of 2019, which under standard utility practices would be considered as approaching end of life. In order to maintain such old

[181] Recently, however, a key politician noted that the sale of the generation is not likely in the near term, given the "lack of market interest". Source: Reorg Research, Inc. "New Advisory Contracts Highlight Key PREPA, Fiscal Reporting Issues." October 9, 2019.

assets as operable, PREPA (or the future owner(s)) will need to spend additional capital and incur hefty operations and maintenance costs.[182]

Figure 32. Average age of PREPA's existing assets by fuel type

Fuel type	Coal	Diesel	Gas	Hydro	Landfill	Oil	Solar	Wind
Average of Age	17	31	20	71	3	44	4	7

Source: Siemens. *Puerto Rico Integrated Resource Plan 2018-2019: Prepared for Puerto Rico Electric Power Authority*. Issued June 7, 2019. Report Number: RPT-015-19. Exhibit 4-1: "Summary of existing plant characteristics and performance."

According to the IRP 2019, about two-thirds of the current CCGT and gas turbine capacity and 80% of the steam-fired capacity that PREPA owns is slated for retirement in the next 10 years. In other words, PREPA's existing assets will shrink from 6,000 MW to only 1,900 MW of capacity by 2029. Buyers will be wary of acquiring assets that have such a short remaining life (a shorter life will reduce the timeframe over which the new operator will be able to earn a profit margin and recoup any investments made).

As predicted in the IRP 2019, the majority of PREPA's fossil-fuel fired operating capacity, faces a great risk of becoming obsolete and/or uneconomic. Many of PREPA's fossil fuel-fired assets were already running infrequently, with over 1,400 MW running less than 525 hours on a fully-loaded equivalent basis in 2018 (or less than 6% average annual load factor).[183] As additional private investment occurs in Puerto Rico (and therefore provides for a more competitive cost of generation), and as electricity demand falls, these older assets will be dispatched less and less frequently.

Any rational buyer of generation assets (or a party contracting to be an independent operator) will evaluate the income generating capability of the asset. They will also evaluate the competitive position of the asset relative to other investments occurring, and whether customer demand for electricity would justify the operations of the plant in the future. In addition, they will look at the contracts (PPOAs) that the seller (in this case, PREPA) would offer for the operation of these generation asset.[184] Buyers will realize that resources that run rarely, for example, because of low electricity demand, would have limited revenue generating value. As such, as part of any due diligence, they will consider the trends affecting the utility's customers (even if they are not directly selling to retail customers) and estimate the maximum willingness to pay of consumers for electricity service. Given the age of the assets and the need for capital spending to keep them operable, buyers would also be cognizant of various operating risks. Overall, the market value of these generation assets will be a function of the income that could

[182] Operating performance of power plants is generally characterized as following the so-called "bathtub curve," where initially there is a high failure rate but soon drops to a low failure rate which is then maintained though much of the life of the plant; however, as the plant ages, the failure rate begins to rise to a high level at the end of its life. At this point, a certain capital investment will be required to obtain plant availability and extension to its life. Source: EOLSS Publishers/ UNESCO. *Encyclopedia of Life Support Systems: Thermal Power Plant and Co-generation Planning – Volume II.*

[183] Siemens. *Puerto Rico Integrated Resource Plan 2018-2019: Prepared for Puerto Rico Electric Power Authority*. Issued June 7, 2019. Report Number: RPT-015-19. Exhibit 4-1 "Summary of existing plant characteristics and performance".

[184] Or if the generation sector would be restructured into a competitive wholesale market, then the buyer would assess the future market price that could be earned in such a market and the asset's competitive position vis-à-vis other producers (generators).

be generated, net of capital investments and operating costs. Similar to other costs of service, the income received by these third-party operators would be limited by rates that PREPA could charge its customers. Furthermore, as PREPA intends to pay for the services of these assets through contracts, buyers will also think about the credit and counterparty risk associated with such contracts. For these various reasons, LEI believes that it is unlikely that third-party buyers will ascribe much economic value to such assets.

9 Conclusions

9.1 PREPA's rates will need to rise from recent historical levels

In last year's Certified Fiscal Plan (from August 1, 2018), PREPA proposed an aspirational goal of keeping rates under 20 cents per kWh. The Puerto Rican government also passed legislation (Act 17-2019) that referred to the 20 cents/kWh "goal" as a key policy objective. Despite the references in Act 17-2019, reality has finally started to set in. In its latest Certified Fiscal Plan dated June 27, 2019, PREPA conceded that rates will need to rise over 25 cents/kWh in the next five years and maybe even substantially higher if: T&D investment and renewable generation investment is more costly than anticipated, or the Federal government funding falls short of the total amount required to rebuild and update the T&D investment, or and energy consumption is lower than expected.

Rates at or below 20 cents per kWh are simply unrealistic when factoring in the magnitude of investment that needs to occur and the need to raise rates to attract private sector operators and investors to help fund and run the various segments of the electric system in Puerto Rico.

9.2 Transition Charge increases the electricity rates faced by PREPA's customers

Some stakeholders to PREPA's Title III process have posited that the Definitive RSA is a reasonable option for dealing with some of PREPA's legacy debt, and therefore benefits PREPA's customers. The Transition Charge is a fixed amount in cents/kWh and the volume risk associated with sufficient collection of revenues to fund the securitization of the new tranches of bonds is the responsibility of the settling parties (bondholders) and not PREPA's customers. However, these features of the Definitive RSA do not change the fact that proposed Transition Charge, by design, increases the overall rate that customers must pay for electricity. Although the Transition Charge starts out below 3 cents/kWh, it will increase over time and, more importantly, continue to affect customers' utility bills for 47 years. The Transition Charge, by virtue of raising the all-in rate that customers must pay for electricity will also contribute to lower electricity consumption which will then increase the rate for remaining customers leading to a difficult and potentially unsustainable cycle of escalating rates.

Based on LEI's analysis, the Transition Charge will exacerbate the incentive to leave the system (for those who can afford it) and accelerate future financial challenges for PREPA.

9.3 There is no silver bullet for lowering rates

Survey of rates paid by customers on other island systems with investor-owned utilities and independent regulatory bodies suggests that PREPA's ambition of reducing costs through regulatory reform and private operations is tenuous. Many of the other island systems surveyed have rates higher than 20 cents/kWh (and where rates are lower, those are a function of unique circumstances that would not apply to Puerto Rico).

Experience with privatizations and implementation of PBR regimes suggest that cost reductions must be tempered with the need to ensure financial stability of the private enterprise. Initial cost reductions after privatization have tended to be in the range of 10% to 20%.[185] However, PREPA has already experienced some of this cost rationalization, for example with reductions in FTEs due to the demographics of the workforce. And additional cost reductions may be challenged politically. Therefore, there may not be a lot of room for cost cutting at PREPA (nevertheless, in the forecast of future rates LEI has generously considered twenty years of productivity improvements for both generation and T&D operations).

Furthermore, moving to incentive ratemaking does not obviate the need for rates to cover the full costs of operation. Based on experiences from other jurisdictions, year-over-year efficiency gains under PBR are typically closer to the 1% range and may even turn negative (implying rates need to rise to improve service quality or finance necessary capital investment). Future efficiencies are also subject to the operator/concessionaire being free to make required changes in staffing – labor laws and political interference may prevent this (although LEI has conservatively assumed that this does not constrain efficiency gains that have been incorporated into PREPA's future cost of service).

In addition, for private ownership to work, rates must cover the full cost of service, including a profit margin for private operators and a return for private investors on their invested capital. PREPA's rates in recent years have not included any return on assets or consideration of repayment of legacy debt. After the 2017 hurricanes, the Federal government committed to fund system restoration efforts. But there is uncertainty about how much Federal government funding will be available once customers have been brought online. The transmission plans are complex, and the T&D investment needs are far greater for a renewable supplied system as compared to one that is served by fossil fuel fired plants. CFP2019 recognizes rates may need to be significantly higher if Federal funding in the future is reduced from current levels.

In summary, global experience with investor-owned business models, privatizations and regulatory reforms suggest that there is no easy path for quick and permanent reduction in rates.

9.4 PREPA's certified Fiscal Plans are not adequate at showing the impact of the Transition Charge

PREPA's Certified Fiscal Plans are not appropriate yardsticks with which to judge whether future rates for electricity are feasible for customers and provide headroom for additional rate increases to remunerate creditors. The CFP looks out five years, but the Transition Charge will be applied to rates for a notional period of 47 years.

CFP2018 and CFP2019 are both too short term to provide an adequate perspective on the sustainability of rate increases and effects of the Transition Charge in the longer term when it rises to over 4.5 cents/kWh. In addition, PREPA's recent CFPs ignore certain future costs (such as additional T&D capex investments that will be necessary in the medium and longer term and

[185] For a more detailed discussion, please see Sections 12.2.1 and 12.2.2.

appropriate fees and profit margins for private operators and investors). The demand forecasts underpinning both CFPs also ignore elasticity of demand for electricity (higher rates will lead to a reduction in electricity consumption).

In order to evaluate whether and how the Transition Charge may affect PREPA's customers, it is vital to consider a long-term rate forecast that covers a timeframe that matches the notional term of the Transition Charge. In addition, the rate forecast needs to be internally consistent and sufficiently dynamic to capture how electricity demand will be impacted by rate increases.

9.5 Transition Charge exacerbates rate increases and accelerates customer defection from PREPA's system

LEI created a conservative, long-term rate forecast for PREPA which shows that customer rates with the Transition Charge will need to rise well in excess of inflationary trends. LEI expects that rates will rise above 30 cents/kWh in the next fifteen years in real dollar (2019) terms under the Base Case and the Alternative Case. There are two primary drivers to the rate increase: T&D investment at some point will need to be financed through customer rates (rather than the subsidies from the Federal government), and higher rates will mean lower electricity consumption, which then forces rates to rise.

LEI's forecast begins with the cost information in CFP2019. However, LEI has adjusted the revenue requirement to contain all the costs that LEI believes would be necessary to provide reliable service to consumers – including "missing items" like additional generation and T&D capex, additional dispatchable generation to support renewable integration, a management fee for the T&D concessionaire, and the cost of pension liabilities. Conservatively, LEI has continued to assume the Federal government would provide free-of-charge financing for as much as 90% of the $16.4 billion for the ten-year T&D investment plan. And LEI has not assumed divestiture of existing generation – if LEI did, PREPA's rates would need to be even higher to account for the recovery of commercially reasonable returns for the new private owners over time. LEI's forecast also contains a bottom up forecast of load that dynamically reflects how electricity rates affect consumer decisions (price elasticity of demand; self-supply optionality).

Given many of the costs (revenue requirements) are fixed, when some customers leave the system and electricity demand falls, this leads to be higher average rates for remaining customers.

Due to the increase in rates, including those related to the Transition Charge, electricity consumption declines by an average rate of 4.2% per annum or a cumulative 70% between FY 2020 and FY 2047 under LEI's Base Case and by 3.5% per annum (for a cumulative decline of 60%) under LEI's Alternative Case. The presence of the Transition Charge accelerates the decrease in electricity demand and may undermine the ability to complete the Transformation (if rates cannot rise any further to accommodate funding of additional investment).

The Transition Charge raises rates that customers must pay. The rate increase due to the Transition Charge will motivate customers to seek out alternatives to PREPA's services and to

reduce their demand for electricity. If rates rise to burdensome levels and total electricity consumption falls, PREPA will face difficulty in meeting its policy goals and mandates.

9.6 There is no other source of income or value to creditors

Raising rates beyond the projected cost of service and the Transition Charge is not practical or reasonable. As noted above, even under conservative assumptions about PREPA's annual revenue requirements, investment needs, and consumers' demand elasticity, total energy consumption falls. Affordability is an issue. And despite the demand protections built into the Definitive RSA, the economics of self-supply are attractive over time. Additional rate increases are likely to yield even further reduction in the volume of electricity sales and revenues to be collected by PREPA.

The sale of existing generation is also not likely to raise significant funds, beyond those recoverable in the near term in electricity rates. Existing generation owned by PREPA is in poor condition and has limited remaining service lives. Buyers will only be willing to pay an acquisition price that they believe can be recovered through their contracts with PREPA. Any contracts with PREPA would need to be rolled into rates and LEI's rate forecast suggests that there is no headroom for rate increases to accommodate amortization of any substantial purchase prices. Buyers of PREPA's existing generation may also be concerned that PREPA could reduce the remaining economic lives of their investment post-divestiture by over-procuring solar and new gas-fired resources; this risk can lead to a discounting of the market value of the assets.

No other source of income or value exists beyond the revenues that could reasonably be expected to be generated by electricity sales (and rates charged) to customers. However, as rates are already expected to rise, there is no additional bandwidth to further raise rates to provide for recovery of amounts owed to unsecured creditors.

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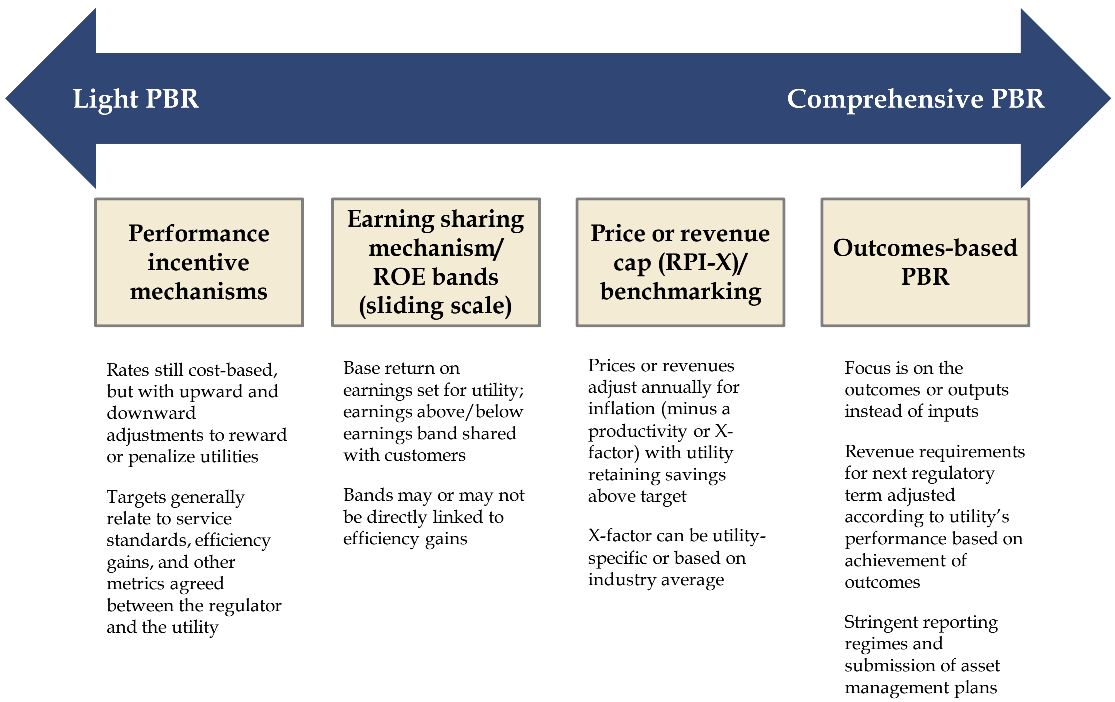
11 Appendix B: Background on Performance Based Ratemaking ("PBR")

PBR aims to create economic incentives for efficiency gains. PBR does not abandon the concept of full cost recovery but rather seeks to adjust how rates are set. In lieu of a detailed examination of costs of service annually, under PBR, regulators will perform such reviews only periodically (every three to five years, typically) and allow the utilities to adjust rates formulaically year over year in between the comprehensive reviews. PBR is best conceptualized as a continuum of incentive-enhancing approaches, ranging from "light" and "narrow" incentive schemes to more "comprehensive" mechanisms, as seen in the figure below.

Figure 33. Continuum on PBR regulation from "light" to "comprehensive"



Light PBR includes mechanisms—such as Performance Incentive Mechanisms[186] and Earning Sharing Mechanisms[187]—where payments to the utilities are adjusted based on their level of performance relative to specific metrics (operational or financial). The "medium" form of PBR mechanism includes the rate cap[188] where either the price or the revenue is capped for the

[186] Performance Incentive Mechanisms ("PIMs") involve metrics, targets, and incentives used to examine, evaluate, and enhance a utility's performance over time by providing information on industry trends and opportunities. Payments to utilities are adjusted upwards or downwards based on the utilities' level of performance. Topics that are measured using PIMs generally include reliability and customer service metrics and can also include policy priorities.

[187] Earning Sharing Mechanisms are designed so that the extraordinary earnings (or losses) are shared among the company and its customers rather than retained (or absorbed) entirely by the company if formulae-driven price adjustments result in a significant divergence between prices and costs.

[188] Unlike a rate freeze, rates under rate caps can change during the regulatory term, based on the approved indexing formula that tracks the inflation rate less an offset to reflect the improvements in productivity that the utility could expect to achieve

regulatory period. This helps promote efficiency as the mechanism tends to change the link between a utility's rates and its costs and improves efficiency.

At the other end of the continuum is Outcomes-based PBR, which is the newest form of PBR, where the focus is on the 'outcomes' (such as customer satisfaction, alignment with policy goals, and service quality), rather than simply costs. This model comes from the UK and is referred to there as the "RIIO" approach. Note however that implementation of this relatively sophisticated version of PBR comes after decades of experience with PBR. Aside from these key PBR mechanisms, there are also other components to PBR rate design such as the length of the multi-year rate plan, productivity factor, treatment of unforeseen events or exogenous factors, off-ramps, and flow-through factors.

Based on experiences in other jurisdictions, well-designed PBR mechanisms have been shown to result in reduced (controllable) costs and better investment decisions. PBR regulations achieve such outcomes because they provide a financial benefit/incentive to the regulated utility, similar to what would motivate companies in competitive markets to control costs and deliver high quality service to their customers. PBR may also reduce administrative and regulatory costs (e.g., due to fewer regulatory proceedings) as well as lead to more stable rates for customers.[189] However, PBR still requires that rates are based on an expectation that an efficient utility can recover its full costs of service. In addition, implementing a PBR regime generally works best in regimes that are at a "steady-state" where unusually large amounts of capital investment are not required, and the consumer growth is predictable. This is not currently the situation in Puerto Rico. A high amount of capital investment is still needed in the short to medium term and the utility will continue to be challenged by the impact of residents leaving the island and utility customers defecting from the grid.

during the regulatory period. Under a rate cap, the utility is required to achieve annual productivity improvements. Furthermore, with a rate cap, a utility's revenues are allowed to diverge from its costs during the regulatory period. The decoupling of costs and revenues incentivizes the utility to increase productivity and decrease costs.

[189] Rate stability under a PBR mechanism is a function of the rate setting formula. Utility rates, typically under an I-X approach will only increase by inflation (I) less the productivity factor (X) plus other flow-through mechanisms. This will be over multiple years, allowing for a longer-term outlook for utility rates. (Source: Olson, Wayne and Caroline Richards. "It's All in the Incentives: Lessons Learned in Implementing Incentive Ratemaking." *The Electricity Journal* 16.10 (December 2003): 20-29.)

12 Appendix C: Details for LEI's projection of PREPA's revenue requirement

Consistent with PREPA categorization of costs, LEI's forecasted revenue requirement for PREPA consists of four sets of costs: (1) labor and operations; (2) cost of non-generation capex; (3) fuel and purchased power; and (4) CILT and subsidies.

LEI's bottom-up forecast of the revenue requirement follows four principles, which were introduced in the main body of the report are repeated here for ease of reference:

- The first principle behind LEI's forecast of the revenue requirement is that PREPA's rates will need to cover the full costs of service in order to move towards a reliable and sustainable business model. As such, capital investments, unless funded with Federal grants or subsidies, will need to be recouped over time through rates.

- The second principle is that the cost of service should be based on a holistic assessment of capital investment needs (generation and T&D): generation investments cannot occur in a vacuum. High levels of renewable integration will require additional T&D investment.[190]

- The third principle recognizes that the costs of service must align with electricity demand levels, while considering variable versus fixed nature of different costs. For example, if electricity demand is rising, more investment may be needed in generation and/or transmission. On the other hand, if in the future, electricity demand falls, variable costs of operation should follow suit (e.g., less fuel will be burned). However, fixed costs may not be able to be reduced proportionally. In fact, previously incurred investment costs, would not be avoidable simply because demand levels are lower.

- The fourth and final principle requires that LEI considers how consumers will respond to the rates that they will be charged based on these costs of service. Economic theory posits that rising prices should motivate consumers to reduce their demand for a product. As such, rising rates for electricity service should reduce future electricity consumption. This phenomenon is not simply theoretical – there is significant empirical research on this subject matter. LEI therefore considers how PREPA's customers will react to the trajectory in rates over time. Consumer response is fed back into the electricity demand projections, which in turn impacts costs of service and resulting rates, providing for a dynamic and internally consistent rate forecast.

12.1 Data relied upon for projecting PREPA's revenue requirements

As noted in Section 4, LEI began evaluating PREPA's future electricity rates by reviewing PREPA's CFP2018. After it was released in late June 2019, LEI analyzed CFP2019 and ensured

[190] In recognition of the fact that renewable generation integration will require significantly more T&D and generation investment over the longer term than contemplated in PREPA's short term Fiscal Plans, and therefore potentially increase the rate burden on PREPA's customers, LEI decelerated the ambitious pace of renewable buildout in legislation. However, LEI also stress tested the possible outcomes with various timetables around renewable mandates. Please see Section 0.

that the starting point for the revenue requirement (cost of service) forecast aligned with the costs for FY2020 reported in CFP2019.[191] Because of the principles noted above, even in the first year of LEI's forecast of revenue requirements (FY 2020), total costs of service are higher than those presented in CFP2019. LEI also included additional costs that were "missing" in CFP2019 in the longer term, such as recurring capex for existing generation, cost allocated for T&D concessionaire profit, capex on the Mercury and Air Toxics Standard ("MATS") compliance in the near term, additional T&D capex to integrate more renewable generation, contribution to regulator's budget, inefficiency dispatch, and additional investment in renewable generation to meet RPS goals.

In addition, LEI used data found in the IRP 2019, Puerto Rico's Act 17-2019, and Excel file submitted by PREPA to PREB on June 21, 2019,[192] as well as data downloaded from the PREPA website[193]. LEI also consulted other reliable data sources including financial data from FOMB Fiscal Plan 2019, historical reported cost data from FERC Form 1, the EIA, NREL, and various financial statements for peer utilities, as well as academic research on productivity gains and elasticity of demand.

12.2 Forecast of future labor and operations costs

This cost category includes O&M costs for the existing (PREPA-owned) generation assets, and O&M costs for the T&D system. O&M costs include both labor and non-labor expenses. LEI has also included projected future costs associated with funding of pension liabilities in this category (because they are labor related). LEI also included T&D concessionaire compensation starting from 2021. In addition, consistent with CFP2018 and CFP2019, LEI included recovery of future capex for PREPA's existing generation (but not T&D capex, which will be discussed under 'Cost of non-generation capex' in Section 12.3 below).

In the future, these functions and costs will not be all within PREPA. Some of these labor and operating costs will be incurred by the T&D concessionaire. If PREPA hires an independent operator for some or all its existing generation, then O&M costs associated with the sold facilities would be recouped through contracts rather than directly incurred expenses. However, for the sake of maintaining the cost structure in LEI's rate model consistent with the layout of PREPA's Fiscal Plans, LEI continues to sum up all the O&M and labor costs and present them as part of this category.

LEI's forecast of PREPA's labor and operations costs, inclusive of the T&D concessionaire compensation and pension liabilities, is presented in the figure below. As shown in Figure 34, the trend of labor and operations costs is relatively steady. The O&M on T&D has the biggest impact – approximately 15% of the labor and operations costs in 2040. LEI's forecast excluded any profit margin or return on assets for existing generation operations (which would make

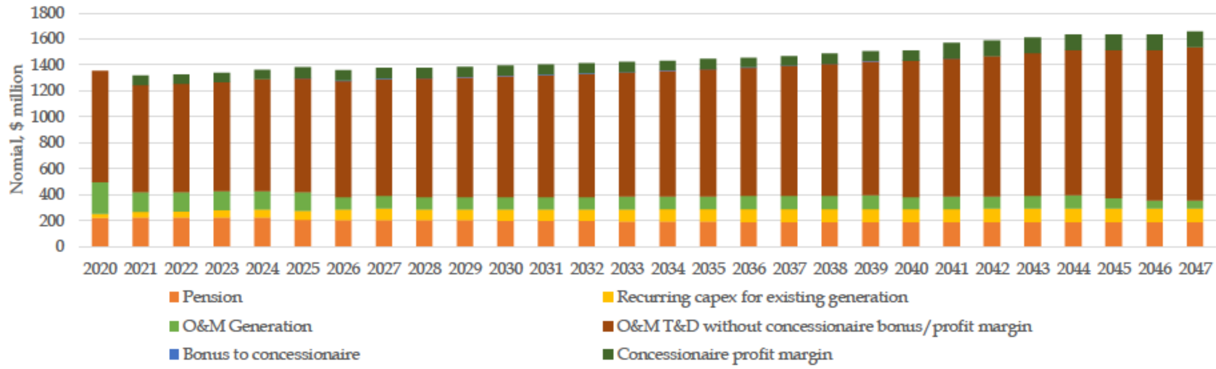
[191] LEI started working on the analysis in early June, when the certificated Fiscal Plan 2019 had not yet been released.

[192] For CILT municipality consumption estimation.

[193] Autoridad de Energía Eléctrica. "Generación, consumo, costo, ingresos y clientes del sistema eléctrico de Puerto Rico." <https://indicadores.pr/dataset/generacion-consumo-costo-ingresos-y-clientes-del-sistema-electrico-de-puerto-rico>

LEI's cost of service projections too low, if PREPA follows through and hires third party operators for the generation assets).

Figure 34. Projected labor and operations costs for PREPA



12.2.1 Projection of O&M costs for existing PREPA generation

The O&M for generation includes: (1) labor operating costs; (2) non-labor operating costs; and (3) non-labor maintenance expenses. In CFP2019, PREPA had estimated $243 million in O&M costs for generation for FY 2020, rising to $254 million in FY 2024. CFP2019 assumes a 1.5% net year-over-year escalation rate.[194] LEI started with the initial number in FY 2020 from CFP2019 and applied an escalator composed of LEI's inflation assumptions (2%) less a target productivity factor (commonly known as an "X factor") to mimic PBR regimes. Although PBR regimes are less common for generation than T&D operations, a price-cap based regulatory system has many similarities to contract-based systems of remuneration that dominate the electric generation landscape around the world. LEI also recognized in the forecast that as power plants are retired, the O&M costs should decline. LEI generally followed the retirement schedule presented in IRP 2019.

Specifically, LEI assumed a 2% X factor in the initial ten years followed by 1.0% X factor (over the FY 2032 to FY 2036 period) and eventually declining to 0% by 2042 (although very few existing generation assets remain operational by that time).[195,196] The inclusion of the X factor

[194] CFP2019. Slide 70.

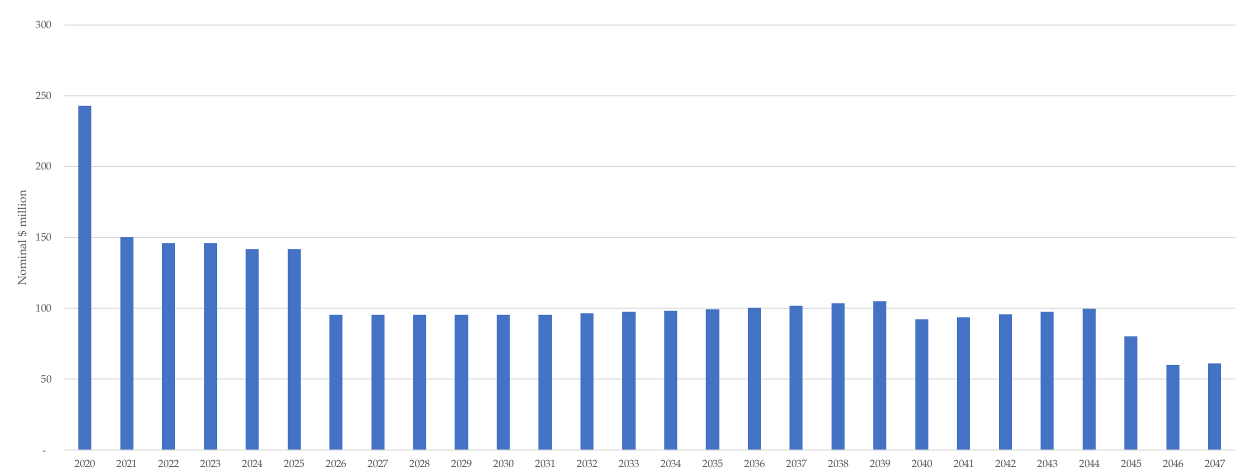
[195] LEI surveyed studies documenting efficiency gains as a result of deregulation in generation in the US and the UK that covered periods between 1985 and 2006. The studies reported an average year-on-year efficiency gain of 2.02%. Sources: Fabrizio, K., Rose, N. and Wolfram, C. *Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on US Electric Generation Efficiency*. 2007; Craig, J. and Savage, J. *Market Restructuring, Competition and the Efficiency of Electricity Generation: Plant-level Evidence from the United States 1996 to 2006*. 2013; Newbery, D. M. G. and Pollitt, M. G. "The restructuring and privatisation of Britain's CEGB: was it worth it?" *Journal of Industrial Economics* 45 (1997): 269–303.

[196] Productivity gains are not likely to be sustained perpetually. Efficiency gains are expected to be most significant during the first few years as the "low hanging fruit" can be quickly addressed, but would then face diminishing returns as the entity catches up with more efficient peers. In the UK, PBR has witnessed declining productivity gains; according to a study prepared for the British Office of Gas and Electricity Markets ("OFGEM"), the average annual total factor productive change in the UK was 2.33% over the 1991/1992 to 1993/1994 period, compared to 1.23% over the 2001/2002 period until 2003/2004. Source: OFGEM. Ajayi et. al. *Productivity growth in electricity and gas networks since 1990*. December 21, 2018.

ensures that LEI's forecast of generation O&M costs includes consideration of efficiency improvements over time from privatization and reforms. The X factor is intended to capture what would have happened under competition; therefore, this same X factor is applicable to a situation where PREPA continues to operate the assets or if it contracts with third parties to operate the assets. However, given there are no known, concrete plans for hiring third-party operators, LEI conservatively did not include any compensation for such third-party operators in the projection of generation-related O&M costs.

LEI's forecasted O&M costs on generation ranges from $60 million to $243 million (as shown in the figure below). Labor and non-labor O&M cost decline over time as existing thermal units from PREPA's assets retire.[197]

Figure 35. Projected O&M costs for generation operations



12.2.2 Projection of O&M costs for T&D

Similar to the sub-categories under O&M costs on generation, the O&M for T&D operations includes labor and non-labor related costs. LEI expects that most of these costs are fixed (and invariant to actual consumer demand in the short term). CFP2019 estimates approximately $858 million of T&D O&M costs for FY 2020, declining in FY 2021 as there is a one-off expense related to Title III restructuring cost in FY 2020, and then rising over time by 1.5% per annum.[198]

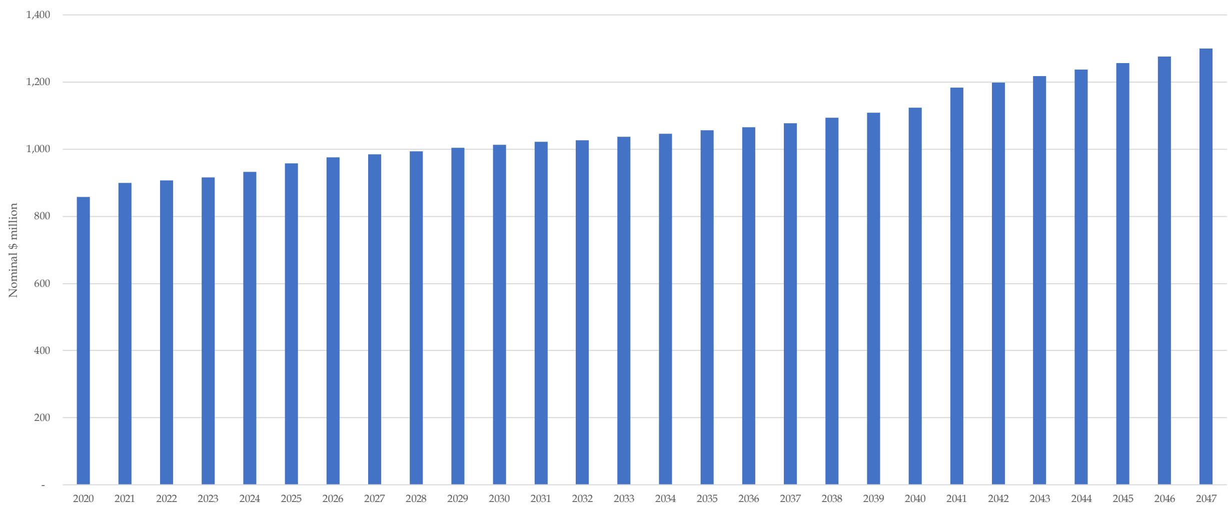
LEI started with the FY 2020 data from PREPA's CFP2019, and then used inflation and the X factor to project future costs for the modeling horizon (however, the X factor starts with FY

[197] Under this forecast, LEI assumed that PREPA or the generation owner of the retiring generation assets would have to reduce labor for O&M. This is a conservative consumption as unionization or existing contracts may forbid the reduction of such costs.

[198] CFP2019, slide 74.

2022, twelve months after the concessionaire begins operations[199]). LEI is essentially assuming that some form of PBR will be put in place to motivate the T&D operator. Based on actual observed experience in North American and UK with total factor productivity trends and reduction in controllable costs LEI set an X factor of 1% for the first 10 years, and then lowered it by 0.5% until reaching 0% by 2043.[200, 201] Projected O&M costs for T&D operations are shown in Figure 36.

Figure 36. Projected O&M costs for T&D operations



12.2.3 Forecasting the compensation for the T&D Concessionaire

As of the writing of this Report, authorities have selected a short-list of potential entities who had responded to P3's request for proposals.[202] However, the final terms of the definitive concessionaire agreement are not known. And as noted in the Declaration of Frederic

[199] As discussed in CFP2019, the T&D RFP process is being conducted by the P3 Authority. According to the timeline, an executed definitive contract is expected in Q4 2020. LEI assumed the concessionaire will take over the operation of T&D in FY 2021. However, the potential efficiency improvement that was described in the CFP2018 and CFP2019 for the near term cannot be achieved immediately. It will take time for the concessionaire to understand the existing system, work on a new operational plan, and implement the new plan and operating system. Thus, LEI conservatively included efficiency improvements starting from FY 2022, 12 months after the concessionaire takes over the operation.

[200] LEI surveyed studies documenting productivity trends in the electric transmission and distribution industries in the US. Over the course of the last fifty years (going back to the 1970s), LEI has seen empirical studies suggest productivity trends ranging from over 1% per annum to less than 0% (negative TFP trends are possible when the pace of input growth is higher than the pace of output (energy load) growth). See for example: Direct Testimony of Mark E. Meitzen, Ph.D., Massachusetts D.P.U. 17-05, January 17, 2017; Rebuttal Testimony of Mark E. Meitzen, Ph.D., Dennis L. Weisman, Ph.D , and Carl G. Degen, Massachusetts D.P.U. 17-05, May 19, 2017; Makholm, J. D., Ros, A. J., & Collins, S. C. "North American performance-based regulation for the 21st century." *The Electricity Journal* 25.4 (2012): 33-47; Makholm, J. D. "The rise and decline of the X factor in performance-based electricity regulation." *The Electricity Journal* 31.9 (2018): 38-43. LEI has chosen to start with a conservative X factor of 1% for T&D operations.

[201] Productivity gains are not likely to be sustained perpetually. Efficiency gains are expected to be most significant during the first few years as the "low hanging fruit" can be quickly addressed, but would then face diminishing returns as the entity catches up with more efficient peers. In the UK, PBR has witnessed declining productivity gains; according to a study prepared for the British Office of Gas and Electricity Markets ("OFGEM"), the average annual total factor productive change in the UK was 2.33% over the 1991/1992 to 1993/1994 period, compared to 1.23% over the 2001/2002 period until 2003/2004. Source: OFGEM. Ajayi et. al. *Productivity growth in electricity and gas networks since 1990.* December 21, 2018.

[202] See P3 website <http://www.p3.pr.gov/prepa-transformation.html>.

Chapados, in support of the Joint Motion of the Definitive RSA, the selection of the "winning Operator" will not be known until late 2019 (the earliest).[203] LEI therefore had to make a number of assumptions about the fees or compensation that a concessionaire would want to earn to take on this role and associated obligations. Consistent with experience with third-party operators for networks and other infrastructure assets, LEI assumed a compensation arrangement consisting of a base compensation fee (with an amount that is fixed for a long term) and an incentive component that is tied to achieved reduction in O&M costs.

The concessionaire's compensation is assumed to be primarily based on PREPA's asset base ("base return"), with the addition of a performance-based incentive calculated as a function of achieved O&M savings. The base compensation rate was estimated by LEI based on benchmarking of the achieved profit margins of other T&D utility business; LEI selected a target return on assets of 1.5%.[204] PREPA's forecasted regulatory asset base was estimated based on the T&D investments and a notional 40-year depreciation profile. In order to get a fixed amount per year for base compensation, LEI first estimated an annual compensation on asset base and then levelized the cumulative sum over a 20-year term, starting with FY 2021, and using a discount rate of 10.8%.[205] For the Base Case, this yielded a base compensation level of $74 million a year.[206] This calculation was repeated again in FY 2041, and then yielded a base compensation rate of $117 million a year in nominal terms for the next 20 years under the Base Case (once deflated, this amount was very close to $74 million in real 2019 terms). The bonus payment is based on sharing of achieved efficiency gains for T&D O&M cost. Given the magnitude of those gains, the annual bonuses range from $1.3 million to $4.7 million during the first twenty years of the T&D concession.

12.2.4 Pension liability costs

In CFP2019, PREPA estimated that restructuring of pension obligations would add 1.4 cents/kWh to as much as 3.1 cents/kWh to base rates from FY 2020 to FY 2034. LEI included the lowest possible cost from PREPA's projections (see the red bar in Figure 37 below).[207] LEI then

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[203] Declaration of Frederic Chapados. In Support of Joint Motion Of Puerto Rico Electric Power Authority And AAFAF Pursuant To Bankruptcy Code Sections 362, 502, 922, And 928, And Bankruptcy Rules 3012(A)(I) And 9019 For Order Approving Settlements Embodied In Restructuring Support Agreement And Tolling Certain Limitations Periods, Filed May 10, 2019 [ECF No.1235].

[204] Based on a weighted average of observed return on assets achieved for comparable T&D utility businesses. LEI calculated a weighted average of 1 56%, which was rounded to 1.5%. This is based on observed return on assets for Island utilities, shortlisted concessionaires identified by the P3 Authority, and the calculated return on assets for the PSEG-LIPA contract in Long Island, NY. Based on relevance, a weight of 60% was assigned to the observed return on assets for the LIPA-PSEG contract, 25% to the return on assets of shortlisted concessionaires identified by P3 Authority, and 15% to observed return on assets for utilities on similarly situated islands (where data is available). Source: Capital IQ. "Operations Services Agreement between LIPA and PSEG." <https://www.lipower.org/wp-content/uploads/2016/10/OSA.pdf>

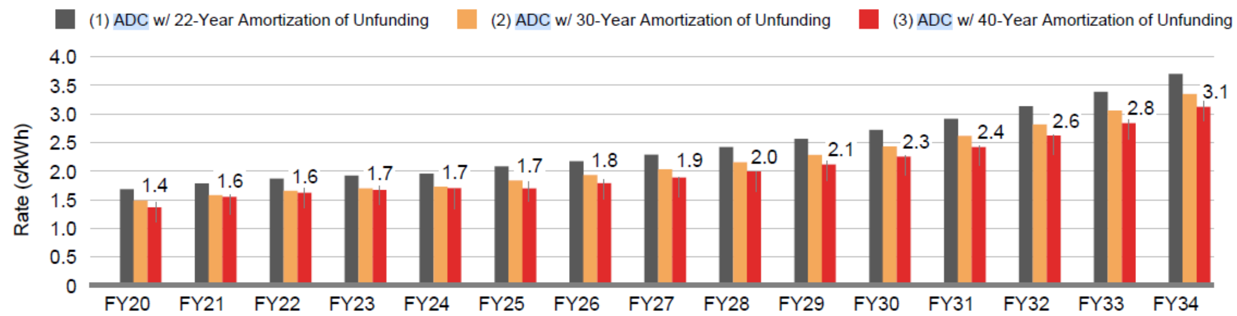
[205] The net present value was calculated in terms of the realized forecasted returns, including a calculation for the time-value of money.

[206] For the Alternative Case, the base compensation rate is lower, at $58 million, because the regulatory asset base is lower due to lower cumulative sum of T&D investment, as discussed further in Section 12.3.

[207] Estimates of the cost of meeting pension liabilities in nominal terms from 2021 to 2024 are taken directly from CFP2019. Data from 2025 to 2038 is obtained from a spreadsheet document named "PREPA_RSA0024465_Confidential.xlsx," which contained pension funding requirement as of October 2018. After 2038, LEI assumed the annual pension funding requirement stays at the 2038 levels in nominal terms.

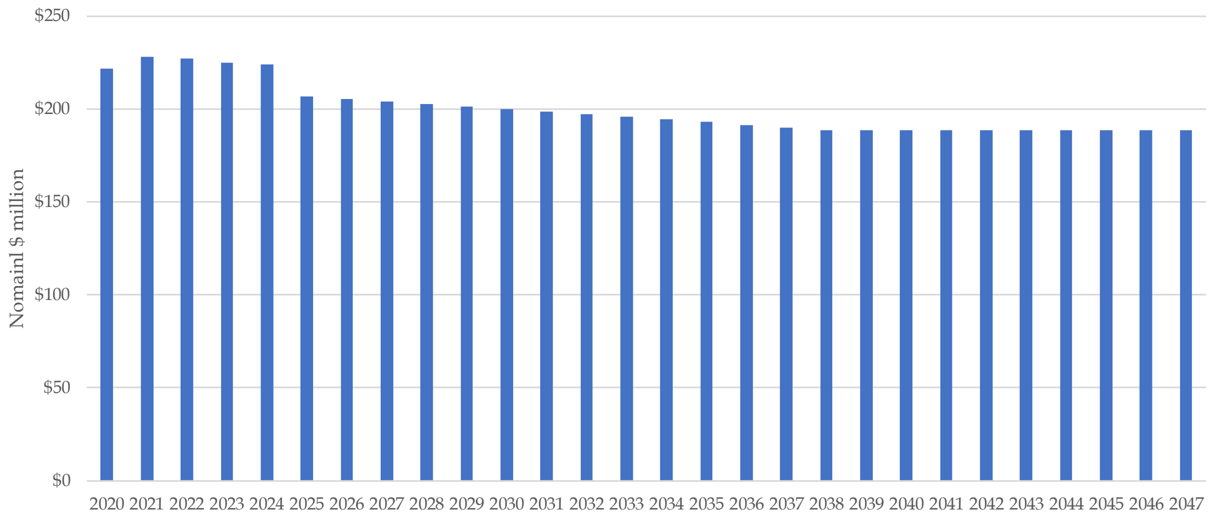
used the annual energy demand projection from CFP2019[208] to convert the pension liabilities into dollar millions (see Figure 38 below), which allows for an accurate reflection of this cost in the total revenue requirement and projected rates.

Figure 37. Projected pension obligation in draft Fiscal Plan (2019)



Source: CFP2019, Slide 87.

Figure 38. Projected pension obligation in $ millions



12.2.5 Capital investment in existing generation

Capital investment ("capex") for generation relates to investments that need to be made to ensure that the existing generation assets remain in operable condition. Capital spending is not recovered in a single year (it is not an expensed cost). Therefore, LEI created a schedule for recovering the capex based on an assumed discount rate and recovery term. The recovery term for the capex was intentionally assumed to be relatively short (10 years), and much shorter than if the investment was contemplated for a new plant, in recognition of the fact that many of these

208 Demand projection on slide 57 from PREPA's CFP2019. As mentioned by PREPA, "load forecasts from FY2025 – FY2034 are linearly extrapolated based on loads between FY2020 and FY2024" (see note on slide 87).

are older assets will be retiring in the coming decade. LEI applied a weighted average cost of capital ("WACC") of 12.85% for the purpose of estimating a financing cost for this capex, which is consistent with the WACC also applied to new generation investment. This WACC was estimated specifically to reflect the risks of generation investment in Puerto Rico.[209]

LEI developed the capital spending levels based on actual capital additions recorded on the balance sheets of generation companies in the US for similar technologies and vintages to those power plants owned and operated by PREPA. Data was sourced from FERC Form 1 data, covering a period of 1995 to 2016. This data covered thousands of operating plants across the US, and therefore represents assets that use the same technology as PREPA's existing generation assets.[210] The resulting values for annual capital additions are presented below for the various technologies relevant to PREPA's assets. These annual capital investment amounts are conservative, as they represent typically only a few basis points of the replacement cost value of such generation technologies.

Figure 39. Annual generation capex by technology

Capex on generation by technology		Average ($/kW)
Gas Turbine	$	19.9
Steam Turbine	$	18.9
Combined Cycle	$	26.1

Source: FERC Form 1. LEI analysis.

In addition, LEI included compliance costs for MATS compliance. PREPA has previously stated that these costs would be incurred from 2020 to 2024.[211] CFP2019 was silent on the breakdown of non-generation capex. Therefore, LEI continues to use the CFP2018 assumptions on annual MATS-related costs.[212]

As shown in Figure 40, LEI forecasted the annual payments to fund generation capex and MATS compliance costs to be in the range of $31 million to $107 million. Capex on generation

[209] The cost of equity in this WACC is based on the average 3-year return (26.19%) for a generation focused exchange-traded fund ("ETF"), in order to reflect the market-accepted risk that generation investors take. Specifically, LEI used the Invesco S&P 500 Equal Weight Utilities Exchange Traded Fund. Source: Invesco. "RYU – Invesco S&P 500® Equal Weight Utilities ETF." <https://www.invesco.com/portal/site/us/investors/etfs/product-detail?productId=RYU&ticker=RYU&title=invesco-s-p-500-equal-weight-utilities-etf>. The cost of debt is based on the current yields for the US 10-year Treasury Bill (approximately at 2.1%) with a risk adder of 6.6% that is based on the estimated spread for below investment grade debt issuances (Source: Damodaran. Stern School of Business. "Ratings, Interest Coverage Ratios and Default Spread." <http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/ratings.htm>). This yields a cost of debt, before taxes, of nearly 8.7%. With an assumed leverage of 70%, and a tax shield of 25%, the overall WACC is 12.85%.

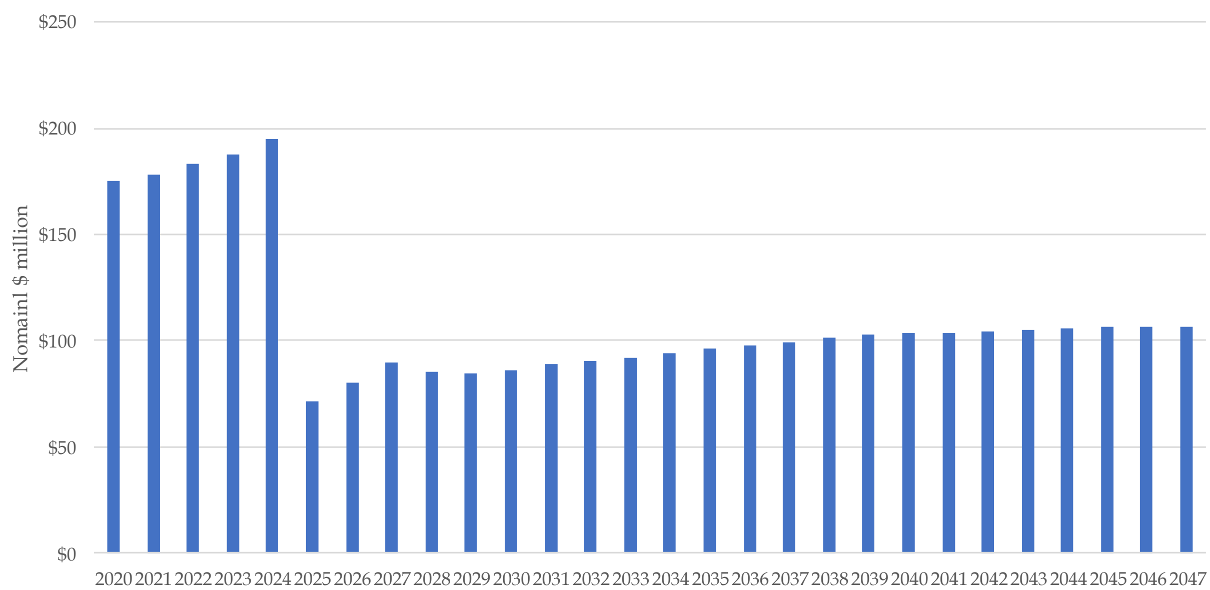
[210] Annual capital spending is inferred from the year-over-year changes in gross asset values. In order to normalize the capital spending to power plant size, LEI also levelized the capital spending by the installed capacity of the plant. This yields a capex figure in $/kW terms. Capex spending was collected for different technologies and vintage of plants; outliers were eliminated and the data was inflated to dollar terms in the year when the unit is built, using a 2% annual inflation. Sample size exceeds 3,000 data points on gas turbines, steam turbines, and combined cycle gas turbines.

[211] CFP2018, slide 35.

[212] LEI kept PREPA's calculation of its MATS compliance costs in LEI's forecast. According to the retirement schedule in the IRP 2019 and CFP2018, these costs arise only in the short term, 2020 through 2024.

decreases after 2026 as retirement of existing units reduces the need to invest in these assets for purposes of maintaining their operations.

Figure 40. Projected annual cost associated with recovery of MATS compliance costs and capex for PREPA's generation



12.3 Cost of non-generation capex (T&D investment)

The cost of non-generation capex relates to T&D investment. PREPA recognizes that it will face a significant capital investment challenge with rebuilding its T&D system. LEI relied on the overall plans for investment that PREPA has published to date: $8.2 billion T&D capex figure for the next 5 years (FY 2020-2024),[213] and a total of $16.4 billion over the next 10 years.[214] However, PREPA explains that this T&D plan is for a minimum level of resilience only.[215] Given this acknowledgement and the fact that LEI's rate forecast needs to extend past FY 2029, the $16.4 billion amount of T&D investment may not be enough. Moreover, PREPA has assumed in its CFP2019 that 90% of the $8.2 billion would be at funded with Federal disaster relief dollars and grants.[216] At some point, the Federal government will stop providing disaster relief-based funding for T&D investment. In fact, PREPA acknowledges that the full $16.4 billion budget from its 10-year Transmission Plan may not be fully funded by Federal funds, and that will cause customer rates to rise.[217]

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[213] CFP2019. Slide 118.

[214] Ibid.

[215] CFP2018. Slide 62.

[216] CFP2019. Slide 66 and slide 118.

[217] CFP2019. Slide 118.

According to COR3, a division within the Public-Private Partnerships committed to ensure Puerto Rico's recovery, "[t]he total cost of deploying a grid that loosely aligns with the vision articulated in *Build Back Better Puerto Rico* and the *Puerto Rico Energy Working Group Build Back Better: Reimagining and Strengthening the Power Grid of Puerto Rico* plans is approximately $30 billion" and "deploying enough new renewable energy to generate 40–50 percent of Puerto Rico's electricity (including sufficient battery storage to ensure system reliability) is estimated to exceed $30 billion and perhaps as much as $90 billion, assuming traditional approaches to handling intermittency of renewable resources, such as solar."[218]

For purposes of creating a conservative Base Case forecast, LEI assumed that total T&D capital spending over the forecast timeframe would equal $30 billion. For consistency, LEI paired the timing of renewable build out with this T&D investment amount. Specifically, LEI's Base Case assumes some deferral of the RPS target (achievement of the 40% renewable target in 2035 as opposed to 2025 as targeted under Act 17-2019). The build out of the $30 billion capital spend generally follows the schedule and information in CFP2019:

- LEI also assumes that $1.95 billion of $16.4 billion capex required to restore and modernize PREPA's grid over the next 10 year is already funded by FEMA (so no ratepayer impacts).

- For the remaining $14.45 billion of the $16.4 billion, LEI assumes PREPA can obtain 90% funding from the Federal government, and therefore will only need to ask customers to finance $1.445 billion over the next 10 years (i.e. FY 2020 to FY 2029) through rates. The fact that LEI used this assumption should not be taken as evidence of LEI's confidence in the likelihood of Federal funding. LEI is employing the same assumption as found in CFP2019 in order to demonstrate that even optimistic assumptions result in cost increases for customers.

- For FY 2030 to FY 2035, an additional T&D capex of $13.6 billion is added in the cost of service forecast, in order to reach the $30 billion cumulative total. LEI assumes additional T&D investment consistent with the low end of COR3's analysis (i.e., cumulative investment of $30 billion). Furthermore, LEI assumes that this $13.6 billion incremental amount would be funded 100% by PREPA's customers, rather than Federal grants.[219]

In order to assess the impact of this T&D capital investment on rates, LEI also considered an Alternative Case, where there was no additional T&D capex after FY 2029. This Alternative Case proxies for a variety of possible future conditions: more efficient investment (so additional capital spend is not needed) or even a change in business strategy for PREPA (i.e., a move away

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[218] COR3. Transformation and Innovation in Wake of Devastation – An Economic and Disaster Recovery Plan for Puerto Rico. July 2018. Page 218 and 219.

[219] It would be highly unrealistic to assume the Federal government will be providing funding for a such a long period of time, and for purposes that are clearly distinct from system restoration and hardening.

from network-centric utility model to a DG-focused business model, where PREPA relies more heavily on DERs).

Figure 41 summarizes the T&D capital spend used in LEI's Base Case and Alternative Case forecasts. To get to an annual repayment schedule, which then goes into the annual revenue requirement, LEI applies a 40-year depreciation term recovery term) and a 10.8% WACC.[220] LEI assumed the T&D investments shown in Figure 41 will be recovered over 40 years given T&D assets have long service lives. LEI's baseline assumptions for the T&D capital spend are extremely conservative (e.g., yielding the lowest possible rates impact) because LEI assumes an expansive amount of Federal funding (nearly $15 billion) and deferral of a large amount of generation and transmission investments into the post-2047 timeframe.

Figure 41. Summary of T&D capital spending under LEI's Base Case and Alternative Case (customer-funded only)

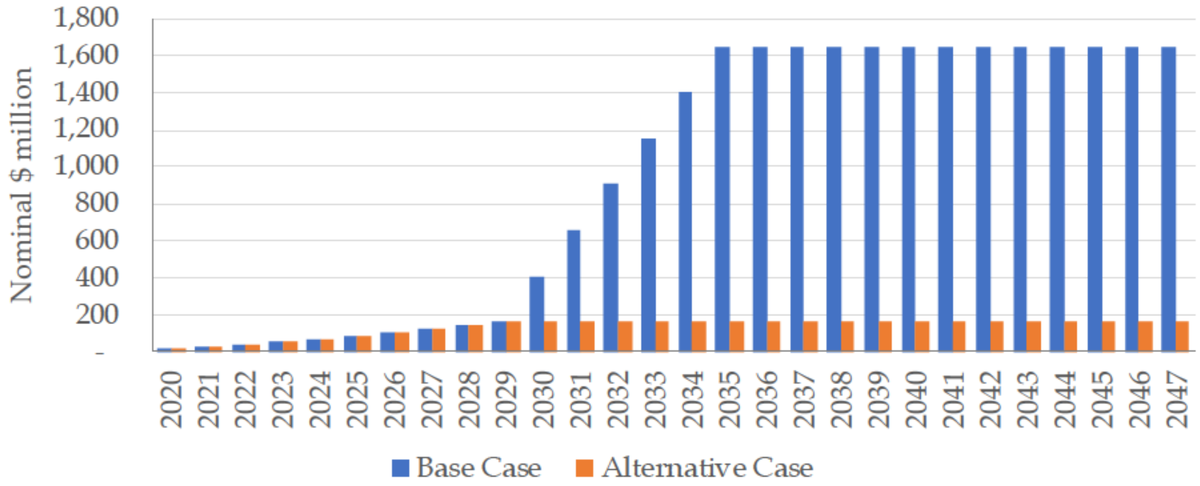
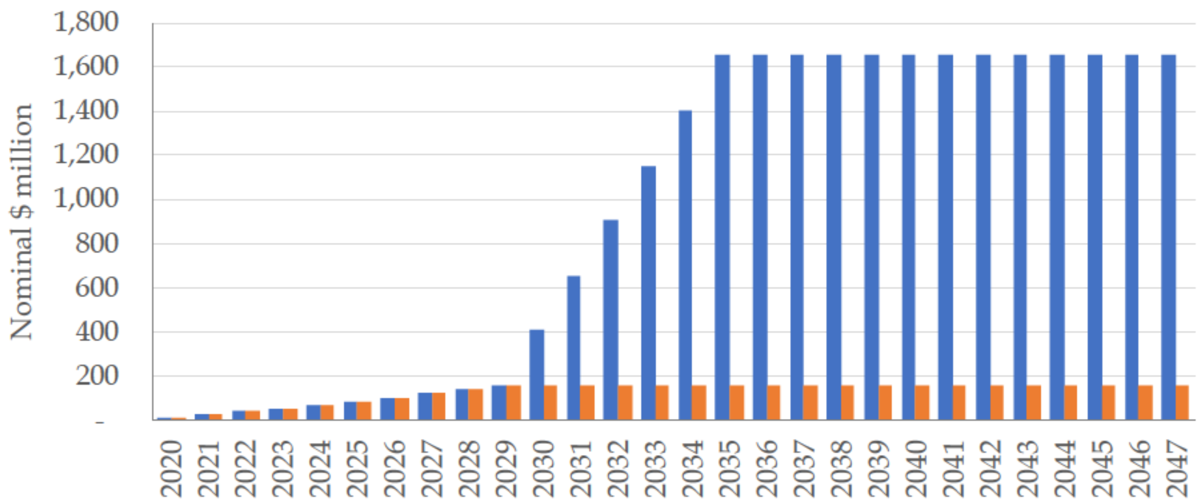


Figure 42 summarizes the projected annual costs of repaying total non-generation capex (T&D investment) under LEI's Base Case and Alternative Case.

[220] LEI estimated a WACC of 10.8% for purposes of financing investment in transmission and distribution. The cost of equity is assumed to align with the observed average authorized return on equity for other Caribbean utilities (which averaged around 12.7%), with an additional 3.35% risk premium, based on the average risk premium for Caribbean, South American, and Central American countries. Specifically, the authorized return on equity based on the observed authorized rates of return for Barbados (13.5%), Dominica (10.44%), and Jamaica (14.13%). The cost of debt is developed from yields on recent 10-year Treasuries (about 2.1%) plus a risk adder of 6.6% based on the default spreads for firms rated slightly below investment grade by Moody's and S&P (*see* Damodaran. Stern School of Business. "Ratings, Interest Coverage Ratios and Default Spread." <http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/ctryprem.html>. LEI assumed a 25% tax rate and a 55% leverage, in line with observed average debt/equity ratios in the US.

Figure 42. Projected annual costs for T&D capex under the Base Case and Alternative Case



12.4 Fuel and purchased power costs

CFP2019 estimates the annual revenue requirement for fuel and purchased power of $2,259 million for FY 2020, declining to $1,531 in FY 2024.[221] The cost of fuel and purchased power contains fuel costs for existing PREPA generation assets (which will evolve over time, with planned conversions and retirements) and also costs of PPOAs with Independent Power Producers ("IPPs"). Those PPOAs cover total costs of operation, including capital-related charges that provide IPPs with a commercial reasonable return. LEI has assumed all future PPOA costs – for new renewables and dispatchable generation (CCGTs, peakers, batteries) - would flow through this cost category.

Rather than rely on the projection of fuel and purchased power costs in CFP2019, LEI estimated these costs independently, so that LEI can ensure that production needs (and therefore generation-related costs) are aligned with the projected energy demand and timeline for renewable deployment. LEI used the latest available information about renewable construction costs, fuel prices, as well as rigorous analysis about investor risk premiums and return targets. LEI relied on the retirements of existing fossil generation as described in the IRP.

12.4.1 Determination of production levels for existing generation

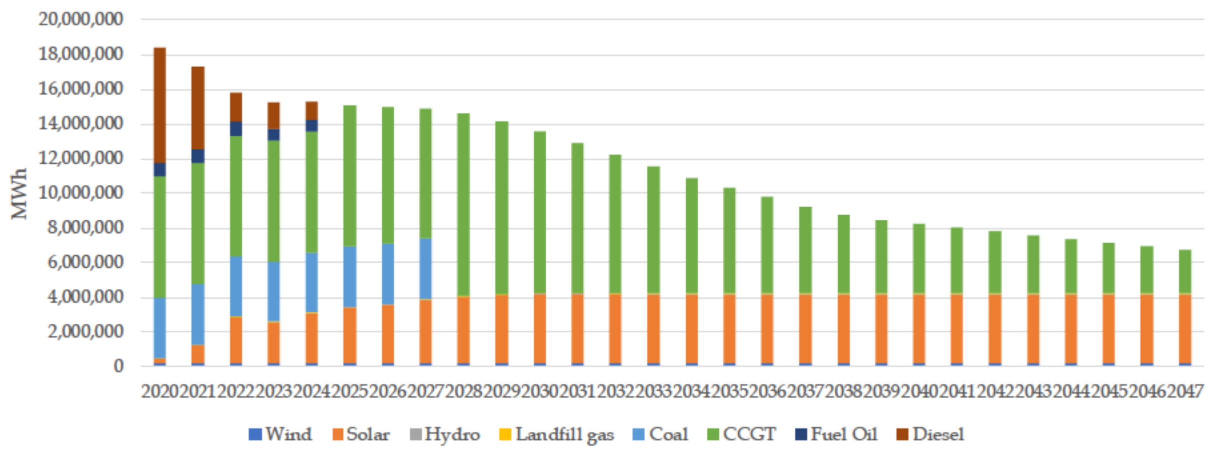
For existing thermal generation, LEI assumed a simplified dispatch order which started with renewable energy (must run generation) and then proceeded to estimate the expected capacity factor of thermal units based on their general relative position in the supply stack.

First, LEI assumed that zero-marginal cost resources (i.e. wind, solar, and hydro) are always utilized to meet load. Then, LEI assumed the coal unit from AES would be the second lowest marginal cost resource. The simplified dispatch model checks whether utilizing the AES coal

[221] CFP2019. Slide 55. Renewable PPAs, Conventional PPAs, and Non-Renewable Fuel are included.

unit up to its historical high load factor would be enough to meet the remaining demand. If not, then the model will repeat the same process for other higher marginal cost resources, in the general order of ascending short run marginal costs: LNG-fired CCGTs, oil-fired CCGTs (until retired), followed by oil-fired steam turbines, then gas turbines (with diesel being the most expensive fuel).

Figure 43. LEI Base Case forecasted dispatch by fuel type using simplified dispatch model



Note: This is simplified dispatch is assuming 60% renewable target by 2050, instead of 100% renewable target by 2050 stipulated in Act 17-2019. This specific assumption is discussed at the start of Section 12 above. Also, for the purposes of this chart, battery installations are not included. They do not produce their own generation, as they simply transfer energy generated from other sources to another time instance. Finally, peakers do not have generation in the figure; LEI assumes the use of peakers is reflected in the inefficient dispatch cost adder.

It should also be noted that the target amount of generation is not the same as the forecasted energy demand. Energy production must exceed energy demand (consumption) in order to account for technical and non-technical losses (losses from transmission and distribution and theft), and ancillary use of energy (on-site demand at PREPA's facilities).

LEI forecasted the amount of electricity theft using the same starting point as IRP 2019 for FY2019, but adjusted future level of theft based on an empirical relationship established in other developing economies with high levels of theft that relate to changes in GNP and the electricity rate (typically, it has been found that the level of electricity theft is inversely related to economic growth, but positively correlated with real changes in electricity rates).[222] This assessment results in a stable rate of electricity theft even though total electricity sales decrease.

12.4.2 Fuel price forecasts

LEI used forecasts published by the Energy Information Agency ("EIA") as a basis for fuel price inputs. Specifically, LEI relied on the Annual Energy Outlook ("AEO") 2019 and Short Term

[222] Jamil, Faisal and Eatzaz Admad. *An empirical study of electricity theft from electricity distribution companies in Pakistan.* <http://pide.org.pk/psde/pdf/AGM29/papers/Faisal%20jamil.pdf>

Energy Outlook ("STEO") from July 2019.[223] Price inputs for Distillate Fuel Oil ("DFO") and Residual Fuel Oil ("RFO") utilize prices from the STEO July 2019 over the 2019-2020 period, then converge to the AEO 2019 forecast levels over the remainder of the forecast time horizon. LEI also utilized the EIA's Henry Hub price forecast from the STEO July 2019 and AEO 2019 as an input for the LNG gas price forecast for Puerto Rico (specifically, the STEO projections for Henry Hub are used for the 2019 – 2020 period, followed by the AEO 2019 long-term forecast levels).

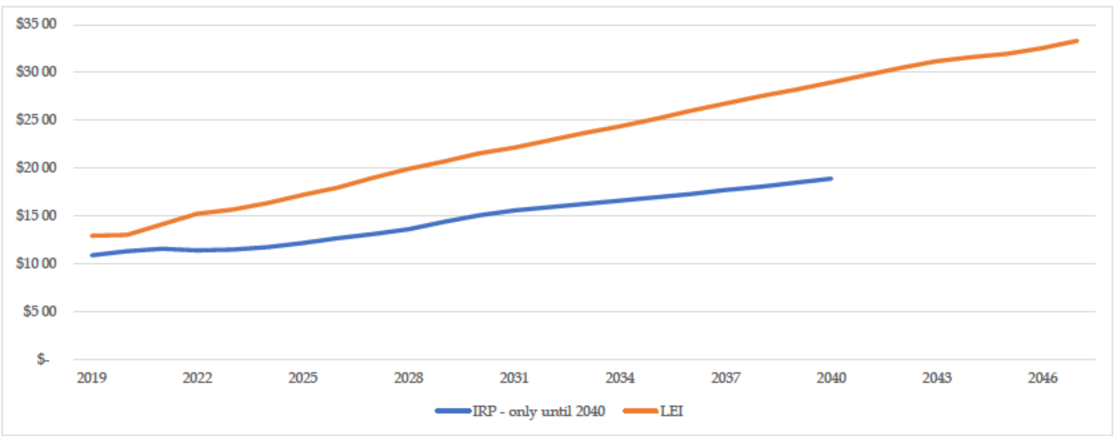
For delivered LNG forecasted fuel prices, the IRP outlines a formula based on Henry Hub prices as follows:

LNG price ($/MMBtu) = Henry Hub ($/MMBtu) * 1.15 + $4.35.[224]

LEI utilized a similar formula as above, utilizing the EIA's Henry Hub price forecast as an input. The STEO results are used for the 2019 – 2020 period, followed by the AEO 2019 levels over the longer term. As LEI utilizes the 2019 AEO figures, compared to the IRP that has relied on analysis from the 2018, LEI anticipates a slight decline in Henry Hub prices over the 2019-2021 term due to increased supply in the US, driven by the shale oil and shale gas production. Over the longer term, the IRP forecasts a slower price growth for LNG, at 1.98% p.a., as compared to 2.24% p.a. under LEI's forecast.

The figures below compare forecast fuel prices to those that are in the IRP (which PREPA implicitly relied on for the CFP2019). Overall, LEI's forecast oil prices are higher than those used in the IRP 2019, but LEI's natural gas prices (LNG, landed in Puerto Rico) are like those in IRP 2019.

Figure 44. Residual fuel oil price forecast comparison



[223] EIA publishes an Annual Energy Outlook ("AEO") that forecasts various energy prices over the long term, as well as a Short Term Energy Outlook ("STEO"). As the EIA's prices are on an annual basis, an adjustment to a Financial Year basis is conducted by calculating the average of the current year with the previous year. For example, the FY2019 data incorporates a 50% weight of 2019 annual average prices, with the other 50% weigh allocated to 2018 annual average prices.

[224] The IRP 2019 outlines that the $4.35 per MMBtu adder represents the costs associated with liquefaction ($2.8/MMBtu), transportation ($1.00/MMBtu) and margin ($0.55/MMBtu)

Figure 45. Distillate Fuel Oil price forecast comparison

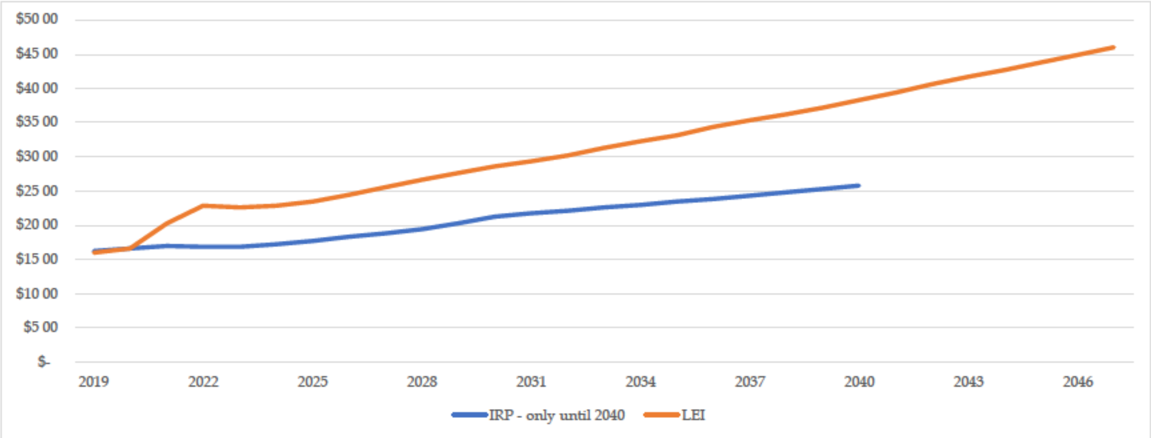
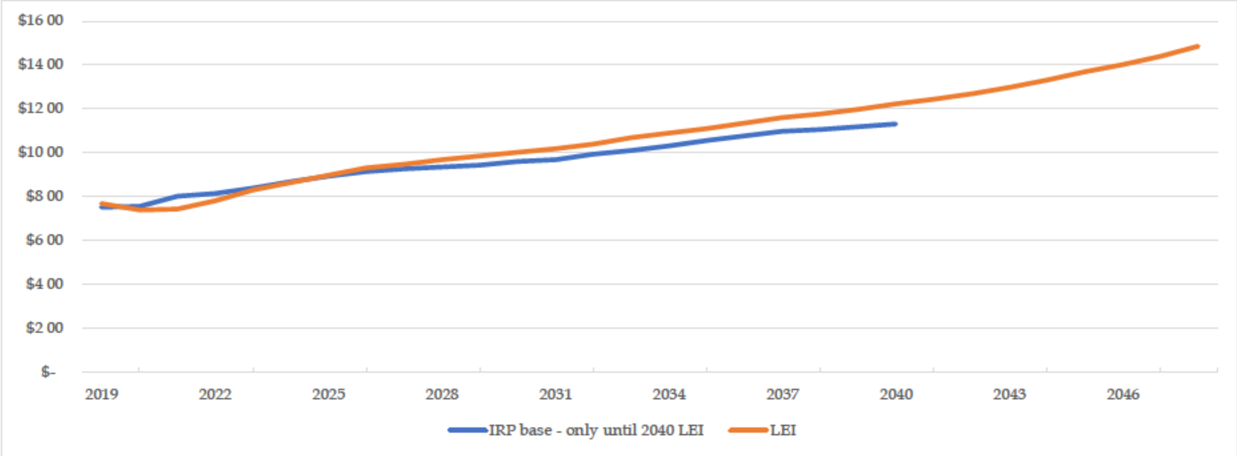


Figure 46. Liquified Natural Gas price forecast comparison



Sources: IRP 2019 and LEI forecast (using Energy Information Administration data, with conversion formula based on IRP 2019.

As mentioned above, LEI utilized price forecasts from EIA AEO 2019 as a basis for all fuel input price forecasts into its tariff model in order to maintain internal consistency. Siemens developed their fuel prices using multiple sources; for example, the benchmark WTI oil price forecast was developed by comparing and averaging price outlooks from sources including EIA and the IEA, while the natural gas price forecast was developed using a third-party gas network model, "Gas Pipeline Competition Model". Utilizing multiple sources, as done by Siemens in the IRP, may create unintended inconsistencies. Moreover, in the IRP, Siemens utilized dated data for its fuel price forecasts. The IRP utilized data published by the EIA as part of its 2018 annual energy outlook, despite the availability of newer data from the EIA; LEI has utilized data from the latest annual energy outlook published by the EIA in January 2019.[225]

[225] For example, the values in Exhibit 7-8 in section 7, page 22 appear to be identical in both the first and second revisions of the IRP, which were published on Feb 12th 2019, and June 7th, 2019, respectively. The EIA's 2019 Annual Energy Outlook was published on January 24th, 2019. Source: EIA. *Annual Energy Outlook 2019*. <https://www.eia.gov/outlooks/aeo/>

12.4.3 Establishing the timing and quantity of new generation investment

LEI forecasted the future generation mix by using forecasted peak demand to determine the amount of generation capacity needed. To set up the supply stack, LEI assumes renewable units will be dispatched first and the remaining capacity should be met by the next cheapest thermal units, which determines the capacity factor of these thermal units in each year. LEI used PREPA existing units in the IRP 2019 as the base, and then LEI incorporated the new entry and retirement schedule based on the Energy System Modernization Plan ("ESM") scenario and the load forecast.[226] Over the longer term, LEI introduced additional renewable generation to meet the RPS goals based on a pragmatic schedule that tries to accommodate the Transformation and balance out rate shock and practical feasibility concerns around trying to build up renewables very quickly.

As shown in Figure 43 above, LEI's forecast starts at the same starting point as CFP 2019, but has a different trajectory over time due to the assumptions made around the timing of compliance with renewable generation goals. In order to ensure reliability, LEI also included several energy storage (batteries) and gas peaking generation projects over the long term. In addition to the energy necessary to meet electric demand from consumers, the system operator must also have sufficient operable capacity to meet peak demand reliably. Generation plants may go on outage, or intermittent energy resources may face production challenges due to weather. Utility operators want to know that they have sufficient total capability to withstand such challenges. In fossil fuel fired system with plenty of dispatchable generation and interconnection with neighboring control areas, NERC has typically required a 15% capacity margin.[227]

In the Fiscal Plan 2018, PREPA projects that the reserve margin will be reduced from 130% in 2018 to 72% in 2023 under its "Aspirational" scenario (with retirement of over 1,800 MW). However, based on experience of system operators in other parts of the world, higher levels of renewable penetration will likely require a higher reserve margin to achieve similar resource adequacy. Siemens has not discussed the quantity of reserves that will be needed in the long run, but LEI would expect that it would be significantly greater than the reserve margin forecast for FY 2023.

For example, the State of Hawaii has aggressive RPS goals as well.[228] The Hawaiian Electric Companies, which serves 95% of residents in the Hawaii, outlined a detailed Power Supply Improvement Plan ("PSIP") on specific actions to help achieve the RPS goals. By comparing the RPS targets with planned installed capacity, LEI observed the Reserve Margins based on installed capacity would increase significantly as the penetration of renewable increases.[229,230]

[226] The IRP and PREPA's CFP2019 present the ESM scenario as the preferred plan. Source: Siemens. *Puerto Rico Integrated Resource Plan 2018-2019: Prepared for Puerto Rico Electric Power Authority*. Issued June 7, 2019. Report Number: RPT-015-19. P. 8-44.

[227] NREC. "Reliability Indicators – M-1 Reserve Margin." <https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin aspx>

[228] Hawaii's RPS goals: 30% by 2020, 40% by 2030, 70% by 2040, and 100% by 2045.

[229] When 30% renewable is achieved, the planned Reserve Margin is 103%; 40%, 70%, and 100% renewable would bring the Reserve Margin to 157%, 179%, and 194% respectively.

Similarly, the New York Independent System Operator ("NYISO") estimated achieving 50% renewable energy in its control area will require that it increase its installed capacity reserve margin more than 2.5 times over its current margin of 17.5% in order to maintain compliance with NERC standards for resource adequacy.[231] If LEI conservatively assumes similar relationships for Puerto Rico, and project that PREPA will need to bring is capacity reserve margin back up to 175% from the projected levels of 72%. This would mean roughly another 770 MW of reliable and dispatchable capacity would be needed in the next twenty years (and only if conservatively assuming no peak load growth). At $443/kW-year annualized cost of batteries in FY2020 and declining over time,[232] 770 MW of such resources would amount to an annualized cost of $291 million per year by 2047.[233]

To ensure consistency with the demand forecast (total annual consumption of energy), LEI relies on a projected peak demand forecast prepared in tandem with the demand forecast (see Appendix D), and target capacity reserve margins based on the rising renewable supply mix in Puerto Rico over the forecast timeframe and experience of other jurisdictions.

Over the course of the forecasted period, near 2,000 MW of solar capacity is required in order to meet the delayed renewable target of 60% by 2050 (see figure below). As renewable energy capacity increases, the reserve margin requirement also increases from the 50% target in 2023 to over 193% by 2047. Retirements in existing thermal units also result in development of peakers and battery storage. Over the modeled period, 770 MW of peakers and battery storage capacity combined is required. Note that this is a conservative assumption as battery storage units generally have less than 25 years of economic life, meaning that some of the battery units installed early part of the forecast period may have to be replaced within the forecast timeframe and that would lead to additional cost. LEI has not included such additional investment costs in LEI's forecast, for the sake of conservativeness.

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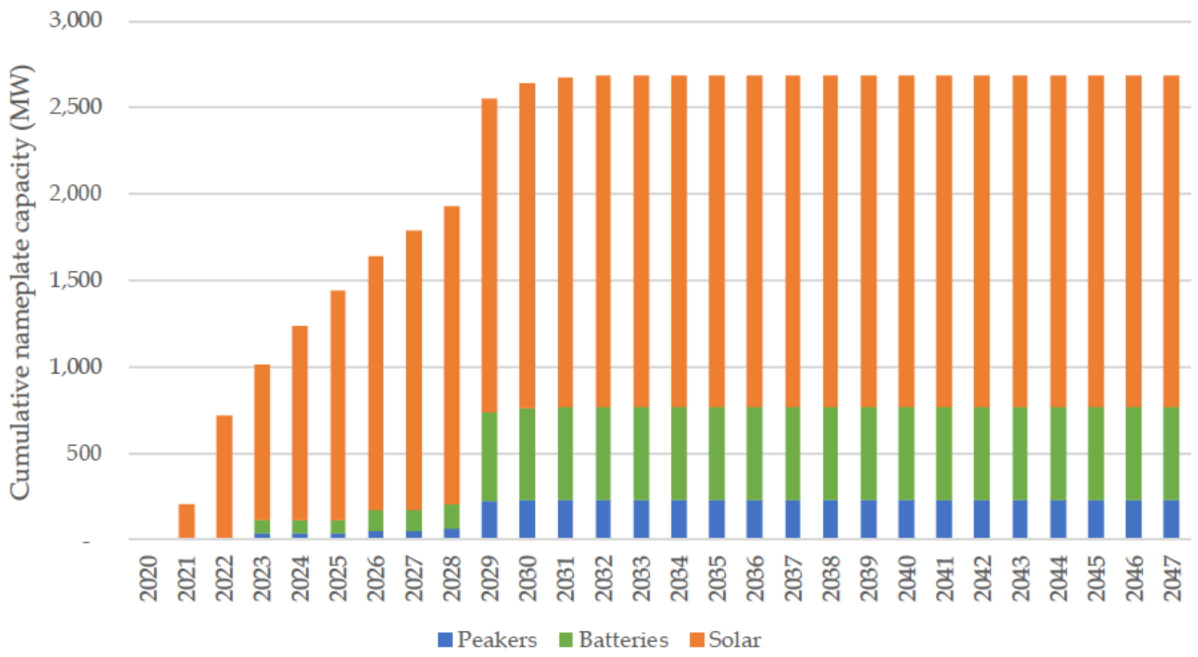
[230] HECO. *Power Supply Improvement Plan*. 2016.

[231] Supplemental Comments of NYISO in Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard. page 9.

[232] Conservatively, LEI incorporated a reduction above and beyond current capital costs to reflect potential future technology gains. Please also see Siemen's projection in the IRP 2019, page 6-30.

[233] Generic peakers and batteries are installed over the course of the forecasted period. LEI assumed that the capital costs of batteries decline at 5% per year in real terms, consistent with IRP 2019's assumptions. Therefore, average levelized cost for peaker and battery facilities over the forecasted period are less than the cost suggested by multiplying the total MWs by the current (2019 $/kW-year) levelized cost.

Figure 47. Forecasted cumulative new capacity required to meet reliably meet renewable target in LEI's baseline



Note: if Puerto Rico were aggressively seeking to meet the 100% renewable goal, then the system would have far fewer peakers and more batteries, which would raise the investment costs

12.4.4 Determining future PPOA costs

Future PPOA costs are modeled by assuming any new generation entering would be owned by independent generators. New entry is forecast to either meet renewable energy targets, or to meet reserve requirements (and this would include specifically new peakers or energy storage facilities). LEI also considered announced new generation plans, according to IRP 2019. The PPOA costs are the product of the MW of new entry by type of unit, and the LCOE of the unit at the year of entry. LEI's assumptions for the LCOEs of various new entry is described in Section 6.3.2.

Figure 48. Summary of LCOE assumptions

Technology	Capital costs (2020$/kW)	Fixed O&M (2020$/kW-year)	Annual charge (2020$/kW-year at 12.9% WACC)
Solar (utility-scale)	1,251	13	191
Wind (utility-scale)	1,979	51	327
CCGT	1,210	11	180
Battery Storage	2,825	9	452
Recip Engine	1,896	30	319

Note: the capacities for solar and wind are not derated, therefore the $/kW-year annual charge does not reflect the cost of which these technologies in providing reliability to the system.

Once LEI has the total capital costs, LEI calculates an annual investment repayment amount based on the return on and off the invested capital. LEI assumed a 20-year repayment period for

all new generation investment, which is generally standardized for levelized cost analysis of various new generation technologies. LEI approximated the return that investors would seek with a WACC of 12.85% (this reflects both the return on equity and the cost of debt). Although the IRP relies on a WACC of 8.5%, LEI believes that this is not reflective of the overall riskiness of investing in generation infrastructure in Puerto Rico relative to similar investments in mainland US.[234] Therefore, for LEI's WACC estimate, the cost of equity is based on the average three-year return (26.19%) for a generation focused ETF, while the cost of debt is based on the current yields for the US 10-year Treasury Bill and a risk adder for sub-investment grade debt. LEI assumes 70% leverage in the capital structure of new IPPs providing services to PREPA, based on survey of the terms of transactions involving new power projects in developing countries by the World Bank Public-Private Partnership Legal Resource Center.[235]

12.5 CILT and subsidies

The CILT and subsidies cost category includes three major costs: compensation in lieu of taxes, other appropriations,[236] and the regulator's budget. CFP2018 estimates annual revenue requirement for this cost category of $238 million for FY18,[237] while CFP2019 estimates $212 million for FY 2020, rising to $254 million in FY 2024. LEI's estimation for FY 2021 matches with CFP2019 estimation of $271 million. Pursuant to legislation, municipalities shall be required to reduce the maximum amount or cap of the energy they receive (CILT) by five (5%) percent annually for three years.[238] Since there is no further information regarding the reduction of cap in the long term, LEI used the 2018 to 2019 municipal consumption cap from PREPA's submission to PREB, and assumed it would continue to reduce by 5% annually throughout the modeling horizon. As for other appropriations, PREPA's budget on this component in June 2018 was used and kept constant for the forecasting horizon.[239]

In CFP2018, PREPA included a $20 million expense for a regulator, beginning in FY 2020 (although, notably PREPA also acknowledged that the annual regulatory budget may need to be as much as $30 million based on their benchmarking with other jurisdictions).[240] Since the release of CFP2018, the $20 million amount has been written directly into legislation.[241]

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[234] For example, in the US, a WACC of 8% to 8.5% is commonly used for determining the cost of new entry in well-established, RTO-run competitive generation markets such as New England, New York and PJM. The risk to a generation investor who builds in Puerto Rico and contracts with PREPA is much higher. Therefore, LEI estimated a custom WACC for generation investments in Puerto Rico. The details behind this custom WACC are described in footnote 209 on page 89.

[235] The World Bank notes an observed debt-to-equity range of 80:20 to 70:30. Source: World Bank. "Public-Private-Partnership Legal Resource center. Financing: Key Issues in Developing Project Financed Transactions." September 6th, 2016. <https://ppp.worldbank.org/public-private-partnership/financing/issues-in-project-financed-transactions>

[236] "Other appropriations" include public lighting and subsidies for special customers, etc.

[237] Calculated by rates and load forecast in PREPA's CFP2018.

[238] P.R. Laws tit. 22, § 212(b)(2)

[239] PREPA's monthly report in January 2019; reported as an annual number.

[240] CFP2018, slides 46 and 59.

[241] "Beginning FY 2019-2020, the annual budget of the Energy Bureau shall be twenty million dollars". Source: *Puerto Rico Energy Public Policy Act* (Act 17-2019) (Approved April 11, 2019), pdf page 126.

Conservatively, LEI assumed the regulator's budget will be $20 million a year throughout the modeling horizon, per Puerto Rico Act 17-2019.

12.6 Total revenue requirement

The yearly revenue requirement discussed in earlier sections are tabulated below. Under the Base Case, the total revenue requirement for PREPA increases from $4.1 billion in FY2020 to $4.7 billion in FY 2047, representing an overall increase of 14%. Under the Alternative Case, the revenue requirement decreases to $3.3 billion by FY 2047, representing a 0.8% decrease per annum and an overall decrease of 19% from the revenue requirement levels in FY 2020.

Although the Base Case and Alternative Case only have assumption differences starting in FY 2030 with respect to the level of T&D capex, this change in revenue requirement also impacts costs in earlier years (such as the T&D concessionaire base management fee and the PPOAs, because the change in demand forecast in later years impacts the amount of new generation built over time). However, such differences have a negligible impact on LEI's rate forecast.

Figure 49. Forecasted revenue requirements by year under LEI's Base Case (nominal $ millions)

Fiscal Year	CILT & subsidies	Labor & Operations	T&D Capex	Fuel & purchased power	Total
2020	274	1,354	157	2,318	4,104
2021	271	1,316	167	2,134	3,887
2022	268	1,327	176	1,584	3,355
2023	264	1,342	186	1,600	3,392
2024	261	1,362	198	1,539	3,360
2025	259	1,379	85	1,388	3,111
2026	256	1,358	103	1,422	3,139
2027	254	1,374	122	1,427	3,177
2028	251	1,378	140	1,478	3,247
2029	249	1,385	159	1,659	3,452
2030	247	1,395	408	1,643	3,692
2031	245	1,405	656	1,611	3,917
2032	243	1,411	905	1,571	4,130
2033	241	1,422	1,154	1,530	4,347
2034	239	1,433	1,403	1,490	4,565
2035	237	1,444	1,652	1,453	4,787
2036	236	1,456	1,652	1,418	4,762
2037	234	1,470	1,652	1,380	4,735
2038	233	1,486	1,652	1,344	4,715
2039	231	1,505	1,652	1,323	4,711
2040	230	1,508	1,652	1,307	4,698
2041	229	1,569	1,652	1,293	4,743
2042	228	1,588	1,652	1,280	4,747
2043	227	1,609	1,652	1,264	4,751
2044	226	1,631	1,652	1,247	4,756
2045	225	1,632	1,652	1,231	4,739
2046	224	1,632	1,652	1,213	4,720
2047	223	1,656	1,652	1,195	4,726

Figure 50. Forecasted revenue requirements by year under LEI's Alternative Case (nominal $ millions)

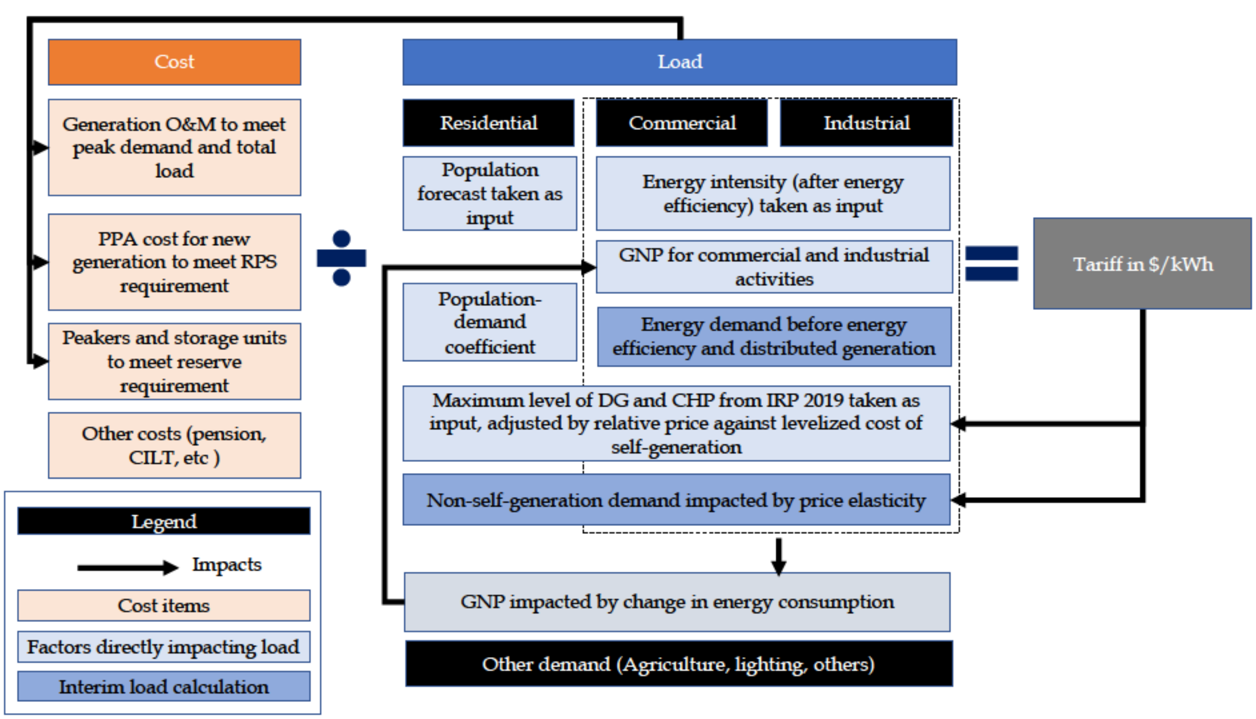
Fiscal Year	CILT & subsidies	Labor & Operations	T&D Capex	Fuel & purchased power	Total
2020	274	1,354	157	2,318	4,104
2021	271	1,300	167	2,134	3,871
2022	268	1,311	176	1,585	3,340
2023	264	1,326	186	1,602	3,379
2024	261	1,346	198	1,543	3,348
2025	259	1,363	85	1,390	3,096
2026	256	1,342	103	1,424	3,126
2027	254	1,358	122	1,429	3,163
2028	251	1,362	140	1,480	3,234
2029	249	1,369	159	1,662	3,438
2030	247	1,379	159	1,645	3,429
2031	245	1,389	159	1,616	3,408
2032	243	1,395	159	1,589	3,386
2033	241	1,406	159	1,567	3,373
2034	239	1,417	159	1,553	3,368
2035	237	1,428	159	1,535	3,360
2036	236	1,440	159	1,529	3,363
2037	234	1,454	159	1,507	3,353
2038	233	1,470	159	1,476	3,338
2039	231	1,489	159	1,458	3,336
2040	230	1,492	159	1,446	3,327
2041	229	1,510	159	1,451	3,348
2042	228	1,528	159	1,440	3,354
2043	227	1,550	159	1,424	3,360
2044	226	1,572	159	1,410	3,366
2045	225	1,572	159	1,396	3,352
2046	224	1,572	159	1,381	3,336
2047	223	1,597	159	1,366	3,345

13 Appendix D: Details around LEI's forecast of electricity demand

In response to the shortcomings of the electricity demand forecast developed in the IRP and used by PREPA in its CFPs discussed in Section 4.2.2, LEI has developed an alternative electricity demand forecast, which has addressed the shortcomings of PREPA's forecast. Specifically, LEI included an interaction between forecasted costs of service, electricity demand, and GNP in its determination of final electricity demand.

LEI has forecast the demand for each major customer class separately, so that LEI can appropriately reflect how residential, commercial, and industrial customers will react to rising costs of service (and rising electricity rates). Generally, as costs rise, the forecasted rate will also rise. In turn, these higher rates feed back into the demand forecast and change the final forecasted demand. The increase in rates coupled with the decrease in demand creates a vicious cycle that adds more and more burden on PREPA customers which leads to a high rate increase trajectory over the forecast period. The interaction between costs of service and the demand forecast is illustrated in Figure 51.

Figure 51. Illustration of LEI's forecasting logic



13.1 Data relied upon

As discussed in Section 12.1, LEI's load and rates forecast relies on data from CFP2018 and CFP2019, IRP 2019, and findings from COR3 report. In addition, the load forecast also relies on data from FOMB's GNP forecast, CIA World Factbook's info on GDP breakdown in Puerto Rico, and academic research on demand elasticity and electricity theft.

13.2 Overview of methodology

When performing load forecast, LEI employed on a hybrid approach. The load forecast is separated into customer classes: residential, commercial, industrial, agriculture, lighting, and others. Each major customer class' (residential, commercial, industrial) demand forecast follows the same over-arching logic, but detailed data sources and logic differ due to the differences in what drives demand for each customer class.

For residential, commercial and industrial demand, the load forecast starts with a baseline demand that matches FY2019 electricity demand from CFP2019, such that there is a common starting point (and recent rebound effect in electricity sales is considered). Then, the impact on demand due to change in rates from actual FY2019 levels to forecasted FY2020 are reflected in future demand levels. A summary of the key forecast drivers for each class of customer is presented in Figure 52.

Figure 52. Overview of LEI's demand forecast approach

Residential

Key drivers:
- Population, demand elasticity
- Level of solar installations
- Development of energy efficiency

Commercial

Key drivers:
- GNP of services industry
- Energy intensity of services industry
- demand elasticity
- Level of solar installation
- Level of CHP installation
- Development of energy efficiency

Industrial

Key drivers:
- GNP of manufacturing industry
- Energy intensity of manufacturing industry
- Demand elasticity
- Level of CHP installation

Others

Including: Agriculture, lighting, others

Same as IRP2019 projected levels

LEI's demand forecast methodology differs from the IRP2019's forecast methodology by adding price elasticity of demand into the forecast, and thus making the interaction between the rate forecast and demand forecast dynamic.[242] Furthermore, the level of customer-owned generation

[242] The implications of the price elasticity of demand re triggered by the percentage change in rates, and not the absolute level of rates. It is reasonable to assume that all classes of customer will face the same percentage rate increase when the average PREPA rate changes over time. Therefore in the rate forecast model, LEI do not distinguish between the specific rates applicable to residential, commercial, industrial, and other classes of customers when forecasting the impact of price elasticity of demand.

also depends on the relative difference between electricity rates and levelized cost of self-generation, which reflects how energy consumers make economic decisions.

One of the key drivers of electricity demand is economic activities, measured in GNP. LEI's analysis starts at the same level of GNP forecast used in CFP2019, but the trajectory of the GNP would differ from the CFP2019 GNP growth rate as LEI's rate forecast model factors the impact of change in electricity usage to economic activities.[243] Notably, changes in commercial and industrial load (after accounting for self-generation) are assumed to impact economic activities – the amount of economic value added contributed by industrial and commercial activities trends with electricity consumption (based on the energy intensity of the activity and the correlation between energy demand change and economic activity change).

13.3 Residential customer demand

For residential demand, the key drivers are population change (taken as exogenous input from IRP 2019), coefficient of population growth and demand growth (taken from backup calculations provided by PREPA's advisors in preparation of CFP2018).[244] This baseline demand forecast is then adjusted by level of energy efficiency (taken as an exogenous input from IRP 2019), level of solar installation (based on LEI's forecast and IRP 2019 projections[245]) and demand elasticity. Based on empirical studies focused on the residential sector, LEI used -0.32 long run elasticity parameter, lagged over three years.

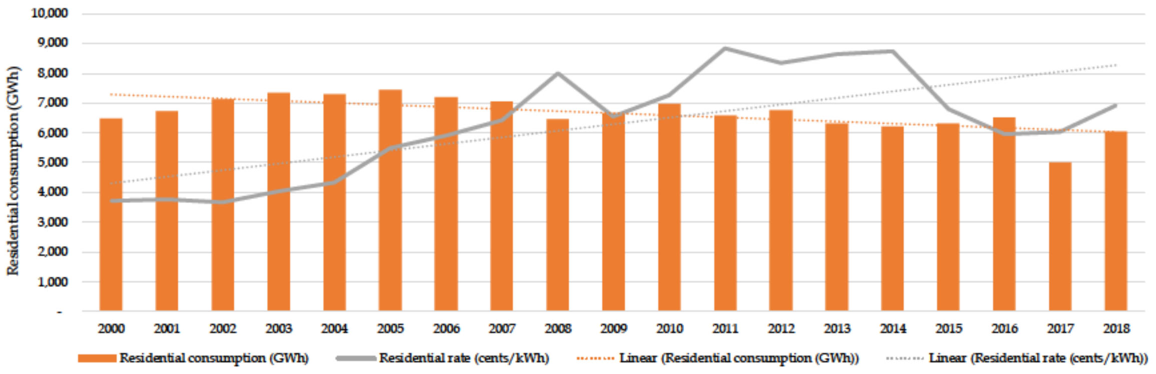
The figure below illustrates the trends in residential consumption and residential rates between 2000 and 2018 in Puerto Rico. As can be seen by the linear trendlines, PREPA's residential rates have generally increased (and notably, they should have increased even further if they were to have achieved full cost recovery), while residential electricity consumption has fallen. A detailed econometric assessment of elasticity is beyond LEI's scope of work, but the overarching dynamics observed in the data suggests a negative correlation, consistent with other empirical studies measuring the elasticity of demand.

[243] It is important to note that the purpose of this exercise is not to forecast Puerto Rico's GNP. LEI uses the base GNP growth rate to develop base GNP forecast as CFP2019 for the near term and IRP2019 for the longer term. The purpose of having a GNP forecast in the rate model is to ensure that LEI has a holistic assessment of electricity consumption.

[244] Excel file received by LEI from Paul Hastings, entitled "0000 00.00 ASSURED-PREPA-9019 MOTION_00018824 PREPA Load Forecast.xlsx"

[245] The level of solar installation depends on the relative LCOE of solar compared against the forecasted all-in rate. However, to be conservative, LEI has capped the cumulative amount of solar PV DG installations by the amount of DG forecast in IRP 2019. Demand elasticity is driven by the low end of long-run residential demand elasticity observed by academic studies.

Figure 53. Historical residential rates versus electricity demand



Source: Autoridad de Energía Eléctrica. "Generación, consumo, costo, ingresos y clientes del sistema eléctrico de Puerto Rico." <https://indicadores.pr/dataset/generacion-consumo-costo-ingresos-y-clientes-del-sistema-electrico-de-puerto-rico>

13.4 Commercial customer demand

For commercial customers, LEI's forecast uses an energy intensity approach, which is based on the inherent relationship between electricity consumed and economic activity (share of GNP represented by commercial customers). The energy intensity was calculated by dividing IRP2019's forecasted energy consumption (after factoring energy efficiency) by the economic activity represented by the service industry in Puerto Rico's GNP. In each forecast year, the level of commercial economic activity (proxied by services sector GNP) follows a base level of growth that is conditioned on IRP 2019's forecasted GNP growth rate from the previous year. Such an approach recognizes the existence of exogenous factors, other than electricity, driving GNP growth. In order to account the level of commercial economic activity tied to electricity sector dynamics, LEI used the ratio of GNP to commercial electricity consumption presented in IRP 2019 to set the energy intensity of the commercial sector.[246] The result of this calculation informs the starting level of commercial electricity demand for the year.

Distributed generation for commercial customers is assumed to increase over time in LEI's forecast logic, if the forecasted rate is 100% higher than the LCOE of self-supply (capped at total potential identified in IRP 2019). The remaining amount of grid connected demand (not-served by DG) is then allowed to react to rising all-in rates, reflecting long-run elasticity of demand. LEI used -0.35 long run elasticity parameter for commercial demand.[247]

Finally, LEI calculated an adjusted services sector GNP for the year, in order to reflect the impact of reduction in electricity consumption by commercial customers (due to price elasticity

[246] Similar to LEI's approach for starting with the FOMB's GNP forecast, LEI has taken as a given the level of electricity intensity (by industrial and commercial classes of customers) from IRP 2019.

[247] Unlike residential and industrial customer classes in Puerto Rico, who have experienced a visible reduction in demand, commercial demand served by PREPA has not seen a long-term directional trend in annual consumption year over year over the 2000-2018 timeframe. However, such historical observations do not undermine the potential that rising rates in the future would lead to reduced consumption.

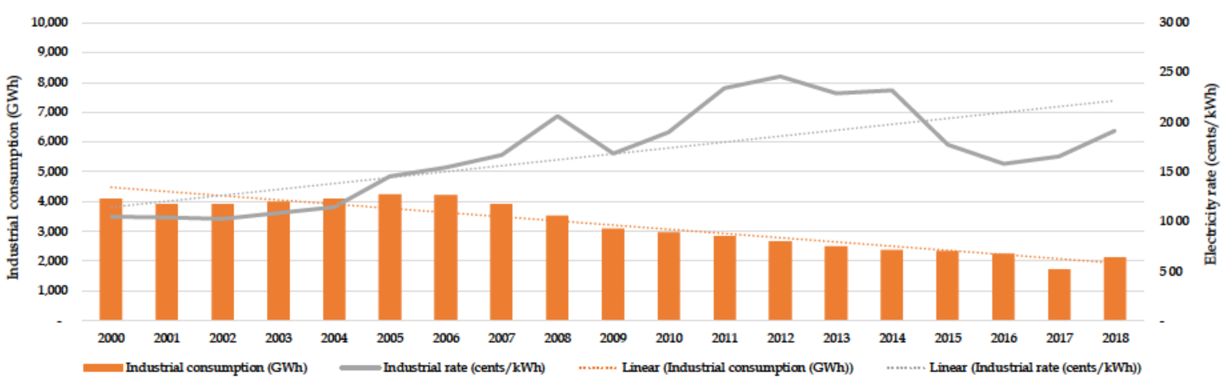
of demand) on economic activity. In computing these adjustments, LEI employed the correlation of change in GNP and change of electricity consumption derived from IRP 2019 forecast numbers. This adjusted GNP is then be used as the starting point to calculate the next year's commercial GNP (before factoring in GNP growth), and consequently the commercial demand in subsequent years.

13.5 Industrial customer demand

The industrial demand forecast is modeled using the same logic as commercial demand. However, the IRP 2019 does not present specific energy efficiency programs for industrial consumers; therefore, there is no adjustment for such activities.[248] However, the IRP 2019 does forecast over 774 MW of CHP initiatives for customer-owned generation. LEI assumed industrial customers will take advantage of these initiatives (while all solar distributed generation are attributed to residential and commercial customers).

Following the same logic used in forecasting the commercial demand, the method used to forecast industrial demand uses manufacturing sector GNP (estimated using implied relationship between GNP forecast and projected electricity demand for the industrial class from the IRP 2019). Once the initial level of industrial demand is set, it is then adjusted by the long run price elasticity of demand in relation to the forecasted electricity rate. LEI used -0.81 long run elasticity factor to project the effects for industrial customers. Although a comprehensive price elasticity of demand study was beyond the scope of this project, historical data on industrial rates and demand indicates increasing rates and declining demand over the 2000 through 2018 timeframe.

Figure 54. Historical industrial rates versus electricity demand



Source: Autoridad de Energía Eléctrica. "Generación, consumo, costo, ingresos y clientes del sistema eléctrico de Puerto Rico." <https://indicadores.pr/dataset/generacion-consumo-costo-ingresos-y-clientes-del-sistema-electrico-de-puerto-rico>

[248] This is reasonable as the IRP's energy efficiency forecast assumes energy efficiency programs that are leveraging external funding (incentives) to motivate reduction in energy use. Industrial consumers already have adequate economic incentives to achieve most economically feasible energy efficiency measures. Energy efficiency initiatives will be customized to the specific customer's needs.

As a final step in the industrial electricity demand forecast, LEI calculated an adjusted manufacturing GNP based on the correlation of change in manufacturing sector GNP and change of electricity consumption derived using IRP 2019 forecast numbers. LEI then used the adjusted GNP values as the starting point to forecast demand in the next year, whereby the next year's GNP growth would be applied to this adjusted GNP value.

13.6 Other customer demand

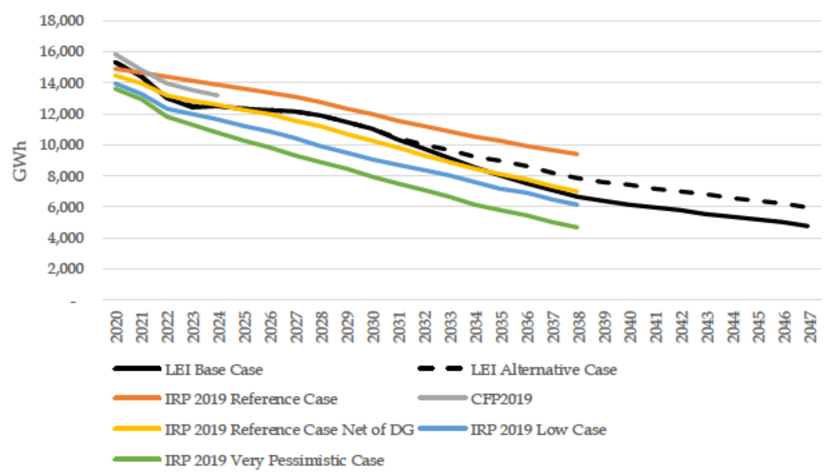
Agricultural, lighting and other classes of customers that are represented in PREPA's electricity forecast are based on the CFP2019 forecast and follow (extrapolated) trends from IRP 2019 over the remaining forecast period.

13.7 Final aggregate demand forecast for grid-connected electricity services in Puerto Rico

LEI's aggregate load forecast for grid-connected electricity supply after considering all the feedback effects and customers' response to rising rates is presented in Figure 55 below. The chart includes both the Base Case and the Alternative Case. The chart also contains various demand forecast scenarios from IRP 2019, as well as the near-term load forecast presented in CFP2019. Notably, LEI's demand forecast follows closely against the IRP 2019 case with energy efficiency and distributed generation.

Under LEI's Base Case, PREPA's electricity demand exhibits a CAGR of -4.5% from FY 2020 to FY 2038, as compared to -4.0% under IRP 2019's Reference Case Net of Distributed Generation, and -4.5% under the IRP 2019 Low Case, and -5.82% under the IRP 2019 Very Pessimistic Case. Over the entire forecasted period in LEI's rate analysis (2019 to 2047), total annual demand for electricity decreases at an annual average rate of 4.2% under the Base Case and at an annual average rate of 3.5% under the Alternative Case. If LEI's projection of future cost of service is higher, for example, by assuming more T&D investments are required, then the forecasted demand would be lower due to higher rates creating a feedback loop (per the long run price elasticity of demand).

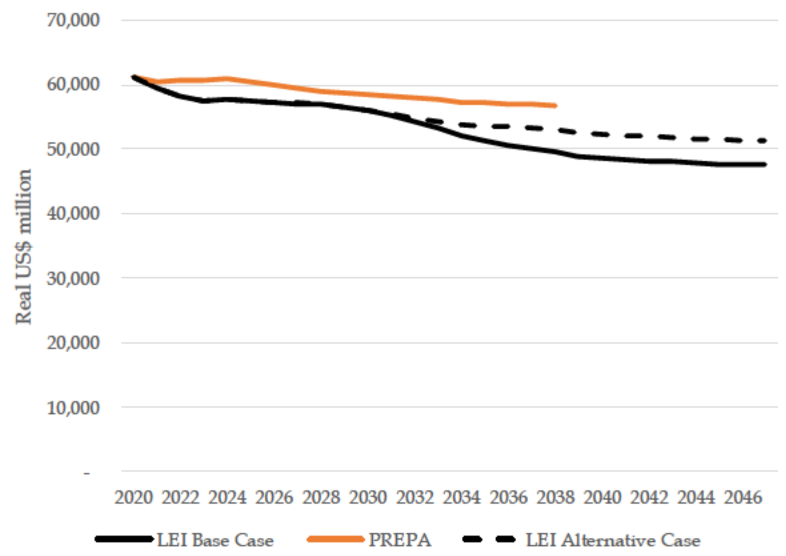
Figure 55. LEI's electricity demand forecast as compared against IRP 2019 and CFP2019



Source: LEI, IRP 2019, CFP2019

LEI's electricity demand forecast is conservative as the elasticity parameters used in the analysis are based on the lowest measurement of long run elasticity identified across various empirical studies (which are discussed in Section 6.2). Also, LEI only considered the impact of change in energy consumption to change in GNP for the commercial and industrial sector, but did not re-estimate the impact of worsening economic conditions on residential demand (i.e., LEI conservatively ignored the likelihood that reductions in GNP would negatively impact household income, which would further reduce electricity consumption). The resulting GNP forecast stemming from LEI's electricity demand under the Base Case is 13% lower by 2038 than the GNP forecast used by PREPA (in CFP2019 and extrapolated using GNP growth rate from IRP 2019).

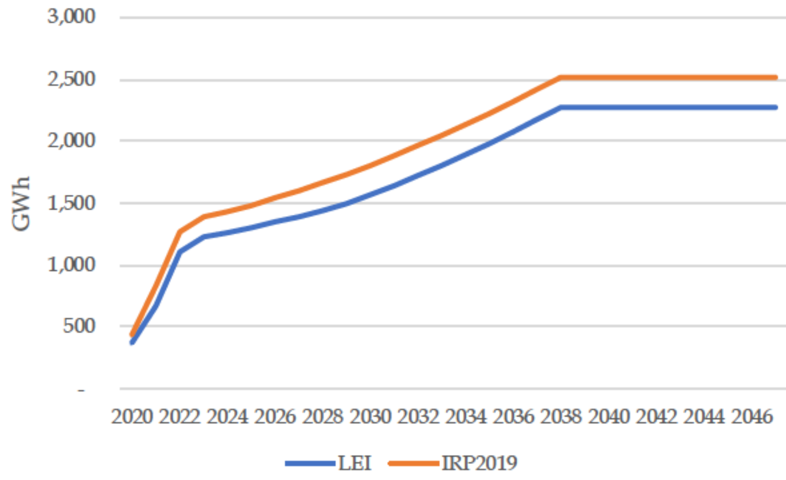
Figure 56. LEI's forecasted GNP vs FOMB's forecast



Source: LEI, IRP 2019

Furthermore, LEI's demand forecast is conservative as LEI capped the amount of self-supply/DG by the total amount of customer-owned generation projected in CFP2019 until FY2024 and IRP 2019 going forward (e.g., total of 992 GWh of CHP generation and 1,599 GWh of solar DG generation by 2038). Deductions for self-supply were only applied if the forecast all-in rates to continue with grid-connected service were higher than the levelized cost of a self-supply solution. This results in lower level of total self-supply deployed in LEI's forecast (2,279 GWh) as compared to customer-owned generation in IRP 2019, as presented in Figure 57. Also, LEI conservatively assumed there will be no additional solar DG or CHP developed after the end of IRP 2019's forecast timeframe, despite the widening gap between LEI's forecasted rates for PREPA and the levelized cost of self-supply.

Figure 57. LEI's Base Case forecast for distributed generation deployment versus customer-owned generation in IRP 2019



Source: LEI, CFP2019 slide 61 for FY2020-FY2024, the adding incremental DG from FY2025 onwards based on IRP 2019 Exhibit 3-18.

Signature

Dated: October 30, 2019

Julia Frayer
Managing Director
London Economics International LLC

Confidential

PREPA Rate Forecast Model

London Economics International LLC

Date 30-Oct-19

Model Description
The purpose of this model is to forecast electricity rates for customers of Puerto Rico Electric Power Authority ("PREPA").
The model is separated into three main parts:
1. Overview, which calculates the forecasted electricity rate
2. Costs, which calculates the costs required for PREPA to perform its regulated business
3. Demand, which calculates the amount of PREPA billable demand

Color Code
Data from PREPA/CFP/IRP/FOMB
LEI Assumption
User choice
Calculated
Units
Header
Do not touch
Comments

Index	Description
Overview	Overview of key modeled results
Common assumptions	Common assumptions used across the model
Settlement and transition fee	Contains information related to RSA settlement and transition fees
Cost - Total	Total PREPA cost of service
Cost - Labor and Operations	PREPA cost for genco and gridco O&M
Cost - T&D capex	PRERA Transmission and distribution capex
Cost - CILT and subsidies	PREPA CILT and subsidies cost
Cost - Fuel and purchased power	PREPA cost for fuel, PPAs, and renewable PPAs
Generation Plan	Forecast of generation required by fuel type and new capacity required
Demand - Total	Total billable demand and generation required
Demand - Residential	LEI forecast of PREPA residential demand
Demand - Commercial	LEI forecast of PREPA commercial demand
Demand - Industrial	LEI forecast of PREPA industrial demand
Demand - Agriculture	LEI forecast of PREPA agriculture demand
Demand - Lighting	LEI forecast of PREPA lighting demand
Demand - Others	LEI forecast of PREPA other demand
Demand elasticity	Source data for demand elasticity
Self generation assumption	Source data for self generation assumptions
WACC assumptions	Source data WACC for T&D and generation

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PREPA Rate Forecast Model - Overview

London Economics International LLC

Scenarios	
Cost	
T&D rebuild and resilience spending in first 5 years for 6B	gov. pay 90%
Federal support for remainder of 16.4 billion of T&D investme	90%

RPS target assumption		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Target scenario		6%	6%	6%					20%							
Target set by law		6%		20%					40%							
Implied yearly target		6%	6%	6%	9%	12%	14%	17%	20%	22%	24%	26%	28%	30%	32%	34%
T&D enhancement to accommodate RPS		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Investment already made to the grid	nominal $/MWh	1,950	1,950	3,016	4,086	5,160	6,237	7,315	8,995	10,675	12,355	14,035	15,715	15,715	15,715	15,715
Additional investments (not automatic)	nominal $/MWh													2,267	2,267	2,267
% funded by Federal government		0.0%														
Total additional investment till 2048	nominal $/MWh	13,600														
Cumulative investment	nominal $/MWh	1,950	1,950	3,016	4,086	5,160	6,237	7,315	8,995	10,675	12,355	14,035	15,715	17,982	20,249	22,515

	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Cost	nominal US dollar million		3,194	3,883	3,660	3,129	3,168	3,137	2,905	2,935	2,973	3,045	3,251	3,493	3,719	3,933
Change	%			21.5%	-5.7%	-14.5%	1.2%	-1.0%	-7.4%	1.0%	1.3%	2.4%	6.8%	7.4%	6.5%	5.8%
Total Demand	GWh		15,967	15,312	14,348	12,983	12,453	12,515	12,345	12,218	12,157	11,899	11,482	10,995	10,379	9,744
Change	%			-4.1%	-6.3%	-9.5%	-4.1%	0.5%	-1.4%	-1.0%	-0.5%	-2.1%	-3.5%	-4.2%	-5.6%	-6.1%
Forecasted rates	nominal $/MWh		200	254	255	241	254	251	235	240	245	256	283	318	358	404
Pension	nominal $/MWh		-	14	16	17	18	18	17	17	17	17	18	18	19	20
Settlement fee	nominal $/MWh		-	10	-	-	-	-	-	-	-	-	-	-	-	-
Transition Fee	nominal $/MWh		-	-	28	28	28	30	30	30	30	30	32	33	34	35
Total rates	nominal $/MWh		200	278	299	286	300	298	282	287	291	303	333	369	412	459
Total rates	c/kWh		20.01	27.8	29.9	28.6	30.0	29.8	28.2	28.7	29.1	30.3	33.3	36.9	41.2	45.9
				39%		-4%	5%	-1%	-6%	2%	2%	4%	10%	11%	12%	11%
Rates in real terms	c/kWh		19.9	27.3	29.0	27.3	28.2	27.6	25.7	25.8	25.8	26.4	28.7	31.4	34.5	37.9
Rates in real terms (without transition charges)	c/kWh			26.4	26.3	24.7	25.6	24.9	23.0	23.1	23.2	23.8	25.9	28.5	31.6	35.0
Forecasted rates without transition charge (nominal)	c/kWh		20.01	26.81	27.10	25.85	27.25	26.85	25.20	25.70	26.13	27.30	30.07	33.58	37.75	42.39

PREPA Rate Forecast Model - Overview cont.

London Economics International LLC

RPS target assumption		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Target scenario				*40%*															*60%*
Target set by law									*60%*										*100%*
Implied yearly target		*36%*	*38%*	*40%*	*41%*	*43%*	*44%*	*45%*	*47%*	*48%*	*49%*	*51%*	*52%*	*53%*	*55%*	*56%*	*57%*	*59%*	*60%*
T&D enhancement to accommodate RPS		**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
Investment already made to the grid	*nominal $/MWh*	15,715	15,715	15,715	15,715	15,715	15,715	15,715	15,715	15,715	15,715	15,715	15,715	15,715	15,715	15,715	15,715	15,715	15,715
Additional investments (not automatic)	*nominal $/MWh*	2,267	2,267	2,267															
% funded by Federal government																			
Total additional investment till 2048	*nominal $/MWh*																		
Cumulative investment	*nominal $/MWh*	24,782	27,049	29,315	29,315	29,315	29,315	29,315	29,315	29,315	29,315	29,315	29,315	29,315	29,315	29,315	29,315	29,315	29,315

	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total Cost	*nominal US dollar million*	**4,152**	**4,371**	**4,595**	**4,571**	**4,546**	**4,527**	**4,523**	**4,510**	**4,556**	**4,560**	**4,564**	**4,568**	**4,551**	**4,532**	**4,538**
Change	*%*	*5.6%*	*5.3%*	*5.1%*	*-0.5%*	*-0.5%*	*-0.4%*	*-0.1%*	*-0.3%*	*1.0%*	*0.1%*	*0.1%*	*0.1%*	*-0.4%*	*-0.4%*	*0.1%*
Total Demand	*GWh*	**9,147**	**8,565**	**8,045**	**7,542**	**7,046**	**6,644**	**6,368**	**6,149**	**5,947**	**5,755**	**5,549**	**5,350**	**5,154**	**4,959**	**4,770**
Change	*%*	*-6.1%*	*-6.4%*	*-6.1%*	*-6.3%*	*-6.6%*	*-5.7%*	*-4.2%*	*-3.4%*	*-3.3%*	*-3.2%*	*-3.6%*	*-3.6%*	*-3.7%*	*-3.8%*	*-3.8%*
Forecasted rates	*nominal $/MWh*	454	510	571	606	645	681	710	733	766	792	822	854	883	914	951
Pension	*nominal $/MWh*	21	23	24	25	27	28	30	31	32	33	34	35	37	38	40
Settlement fee	*nominal $/MWh*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transition Fee	*nominal $/MWh*	36	37	38	39	40	40	42	43	44	45	46	46	46	46	46
Total rates	*nominal $/MWh*	511	570	633	670	712	750	781	807	841	870	902	935	965	998	1,037
Total rates	*c/kWh*	**51.1**	**57.0**	**63.3**	**67.0**	**71.2**	**75.0**	**78.1**	**80.7**	**84.1**	**87.0**	**90.2**	**93.5**	**96.5**	**99.8**	**103.7**
		11%	11%	11%	6%	6%	5%	4%	3%	4%	3%	4%	4%	3%	3%	4%
Rates in real terms	*c/kWh*	41.7	45.7	50.0	52.1	54.4	56.5	57.7	58.4	59.7	60.5	61.5	62.5	63.2	64.1	65.3
Rates in real terms (without transition charges)	*c/kWh*	38.7	42.8	47.0	49.1	51.4	53.4	54.6	55.3	56.6	57.4	58.4	59.4	60.3	61.2	62.4
Forecasted rates without transition charge (nominal)	*c/kWh*	47.53	53.31	59.52	63.15	67.22	70.98	73.99	76.41	79.78	82.51	85.64	88.91	91.96	95.20	99.10

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PREPA Rate Forecast Model - Settlement and transition fee

London Economics International LLC

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Settlement fee	*Nominal $/MWh*		*0*	*10*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Transition fee	*Nominal $/MWh*		*0*	*0*	*27.68*	*27.68*	*27.68*	*29.57*	*29.57*	*29.57*	*29.57*	*29.57*	*32.42*	*33.23*	*34.06*	*34.92*

Source RSA

			2068											
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Final Consumption	**GWh**	15,312	14,348	12,983	12,453	12,515	12,345	12,218	12,157	11,899	11,482	10,995	10,379	9,744
Revenues for new security		$ 153,120	$ 397,160	$ 359,373	$ 344,689	$ 370,079	$ 365,027	$ 361,288	$ 359,492	$ 351,844	$ 372,235	$ 365,372	$ 353,492	$ 340,268

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PREPA Rate Forecast Model - Settlement and transition fee cont.

London Economics International LLC

		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Settlement fee	*Nominal $/MWh*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Transition fee	*Nominal $/MWh*	*35.79*	*36.68*	*37.6*	*38.54*	*39.5*	*40.49*	*41.5*	*42.54*	*43.61*	*44.7*	*45.52*	*45.52*	*45.52*	*45.52*	*45.52*

		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Final Consumption	**GWh**	9,147	8,565	8,045	7,542	7,046	6,644	6,368	6,149	5,947	5,755	5,549	5,350	5,154	4,959	4,770
Revenues for new security		$ 327,375	$ 314,155	$ 302,492	$ 290,664	$ 278,321	$ 269,030	$ 264,288	$ 261,591	$ 259,348	$ 257,243	$ 252,600	$ 243,555	$ 234,630	$ 225,717	$ 217,125

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PREPA Rate Forecast Model - Common Assumptions

London Economics International LLC

	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Baseline GNP forecast used I model	*Real Millions US dollars*	$ *56,900*	$ 60,100	$ 61,000	$ 60,400	$ 60,500	$ 60,600	$ 60,900	$ 60,422	$ 59,948	$ 59,478	$ 59,011	$ 58,606	$ 58,340	$ 58,076	$ 57,814
Source	FOMB fiscal plan 2019 (Certified May 9 2019)															
GNP in CFP 2019	*Real Millions US dollars*	$ *56,900*	$ *60,100*	$ *61,000*	$ *60,400*	$ *60,500*	$ *60,600*	$ *60,900*								
Source	CFP 2019															
FOMB GNP forecast	*Nominal Millions US dollars*	$ *68,366*	$ *71,565*	$ *73,435*	$ *73,778*	$ *74,977*	$ *76,128*	$ *77,670*	$ *78,216*	$ *78,767*	$ *79,321*	$ *79,879*	$ *80,441*	$ *81,198*	$ *81,962*	$ *82,733*
FOMB Inflation	*%*	*1.60%*	*0.60%*	*1.10%*	*1.40%*	*1.50%*	*1.50%*	*1.50%*	*1.50%*	*1.50%*	*1.50%*	*1.50%*	*1.40%*	*1.40%*	*1.40%*	*1.40%*
CAGR	*%*	1.16%						0.70%					0.94%			
FOMB Inflation index		1.00	*1.01*	*1.02*	*1.03*	*1.05*	*1.06*	*1.08*	*1.09*	*1.11*	*1.13*	*1.14*	*1.16*	*1.18*	*1.19*	*1.21*
Implied real static GNP		$ 68,366	$ 71,138	$ 72,203	$ 71,538	$ 71,627	$ 71,651	$ 72,022	$ 71,457	$ 70,897	$ 70,340	$ 69,788	$ 69,309	$ 68,995	$ 68,683	$ 68,372
Implied real GNP growth rate									-1%	-1%	-1%	-1%	-1%	0%	0%	0%
Source	FOMB fiscal plan 2019 (Certified May 9 2019)															
change	*%*		5.62%	1.50%	-0.98%	0.17%	0.17%	0.50%	-0.78%	-0.78%	-0.78%	-0.78%	-0.69%	-0.45%	-0.45%	-0.45%
Population	*thousands of people*	*3168*	*3112*	*3061*	*3013*	*2971*	*2935*	*2903*	*2,878*	*2,853*	*2,828*	*2,803*	*2,779*	*2,747*	*2,715*	*2,684*
CAGR	*%*	-0.67%						-0.87%					-1.16%			
Population (FOMB 2018)	*thousands of people*	*3143*	*3104*	*3084*	*3039*	*2995*	*2951*	*2910*	*2871*	*2833*	*2794*	*2756*	*2718*	*2681*	*2644*	*2609*
Source	FOMB fiscal plan 2019 (Certified May 9 2019)															
change	*%*		-1.77%	-1.64%	-1.57%	-1.39%	-1.21%	-1.09%	-0.87%	-0.87%	-0.87%	-0.87%	-0.87%	-1.16%	-1.16%	-1.16%
GNP per capital	*Real US dollars*	$ 17,961	$ 19,312	$ 19,928	$ 20,046	$ 20,364	$ 20,647	$ 20,978	$ 20,996	$ 21,014	$ 21,032	$ 21,050	$ 21,089	$ 21,239	$ 21,390	$ 21,542
Inflation	%	*2.0%*														
Source	*FED FOMC*															
Inflation adjustment factor			1.00	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27	1.29

General assumptions

WACC for new generation	*%*	12 85%
WACC for transmission	*%*	10 80%
Solar capacity factor	*%*	*22.00%*
Wind capacity factor	*%*	*25.00%*
Puerto Rico cost adder	*%*	*16.00%*

LCOE summary	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Solar LCOE (Shown in IRP)	*$/MWh*	$ 69	$ 67	$ 63	$ 64	$ 67	$ 78	$ 77	$ 76	$ 76	$ 75	$ 74	$ 73	$ 72	$ 72	$ 71
Solar (Utility-Scale) LCOE (Calculated)	*$/MWh*	$ 73	$ 71	$ 71	$ 70	$ 70	$ 69	$ 69	$ 95	$ 94	$ 93	$ 92	$ 91	$ 90	$ 91	$ 91
Wind (Utility-Scale) LCOE (Calculated	*$/MWh*	$ 111	$ 112	$ 112	$ 114	$ 115	$ 116	$ 118	$ 161	$ 163	$ 165	$ 167	$ 169	$ 172	$ 174	$ 176
CCGT LCOE (Calculated)	*$/MWh*	$ 80	$ 76	$ 78	$ 79	$ 80	$ 82	$ 83	$ 84	$ 85	$ 86	$ 87	$ 89	$ 90	$ 92	$ 93
Small CCGT LCOE (Calculated)	*$/MWh*	$ 159	$ 155	$ 159	$ 160	$ 162	$ 164	$ 166	$ 168	$ 171	$ 172	$ 175	$ 177	$ 179	$ 182	$ 185
Battery Storage LCOE (Calculated)	*$/MWh*	$ 108	$ 106	$ 104	$ 102	$ 100	$ 98	$ 97	$ 95	$ 94	$ 92	$ 90	$ 89	$ 87	$ 86	$ 84

Solar (utility-scale)

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Capital Cost	*$2018/kW*	*$ 1,100*	*$ 1,080*	*$ 1,060*	*$ 1,040*	*$ 1,019*	*$ 998*	*$ 977*	*$ 956*	*$ 934*	*$ 913*	*$ 892*	*$ 871*	*$ 850*	*$ 841*	*$ 831*
Puerto Rico cost adder	*%*	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Puerto Rico Capital Cost	*$2018/kW*	$ 1,276	$ 1,253	$ 1,230	$ 1,206	$ 1,182	$ 1,157	$ 1,133	$ 1,108	$ 1,084	$ 1,059	$ 1,035	$ 1,010	$ 986	$ 975	$ 964
Inflation adjusted	*Nominal $/kW*	$ 1,276	$ 1,261	$ 1,251	$ 1,244	$ 1,237	$ 1,230	$ 1,222	$ 1,213	$ 1,204	$ 1,195	$ 1,185	$ 1,173	$ 1,160	$ 1,164	$ 1,167
Source		*NREL ATB 2019, average total overnight cost for utility scale PV across US regions, mid case*							-2 3139%					-1 1341%		
Capacity Factor	*%*	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%
Fixed O&M	*$2018/kW-year*	*$ 14*	*$ 13*	*$ 13*	*$ 12*	*$ 12*	*$ 12*	*$ 12*	*$ 11*	*$ 11*	*$ 11*	*$ 11*	*$ 10*	*$ 10*	*$ 10*	*$ 10*
Inflation and x-factor adjusted	*Nominal $/kW-year*	$ 14	$ 13	$ 13	$ 13	$ 12	$ 12	$ 12	$ 12	$ 11	$ 11	$ 11	$ 11	$ 11	$ 10	$ 10
Source		*NREL 2018 annual technology baseline mid-case*														
WACC	*%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*
Source		*LEI assumption/ IRP2019*														
ITC	*%*	*30.0%*	*30.0%*	*30.0%*	*30.0%*	*30.0%*	*30.0%*	*30.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Economic life	*years*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*
Source		*IRP 2019*														
LCOE	*Nominal $/MWh*	$ 73	$ 71	$ 71	$ 70	$ 70	$ 69	$ 69	$ 95	$ 94	$ 93	$ 92	$ 91	$ 90	$ 91	$ 91
LCOE	*Nominal $/kW*	$ 194	$ 191	$ 189	$ 188	$ 187	$ 186	$ 184	$ 183	$ 181	$ 180	$ 178	$ 176	$ 174	$ 175	$ 175

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PREPA Rate Forecast Model - Common Assumptions (2)

London Economics International LLC

	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Wind (utility-scale)																
Capital Cost	*$2018/kWdc*	*$ 1,672*	*$ 1,675*	*$ 1,677*	*$ 1,680*	*$ 1,682*	*$ 1,685*	*$ 1,687*	*$ 1,690*	*$ 1,693*	*$ 1,696*	*$ 1,699*	*$ 1,702*	*$ 1,705*	*$ 1,708*	*$ 1,711*
Puerto Rico cost adder	*%*	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Puerto Rico Capital Cost	*$2018/kW*	$ 1,940	$ 1,943	$ 1,946	$ 1,948	$ 1,951	$ 1,954	$ 1,957	$ 1,961	$ 1,964	$ 1,967	$ 1,971	$ 1,974	$ 1,977	$ 1,981	$ 1,985
Inflation adjusted	*Nominal $/kW*	$ 1,940	$ 1,954	$ 1,979	$ 2,009	$ 2,043	$ 2,076	$ 2,111	$ 2,146	$ 2,182	$ 2,218	$ 2,255	$ 2,291	$ 2,327	$ 2,364	$ 2,402
Source		*NREL 2018 annual technology baseline mid-case (TRG-8)*														
Capacity Factor	*%*	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Fixed O&M	*$2018/kW-year*	*$ 51*	*$ 50*	*$ 50*	*$ 49*	*$ 49*	*$ 49*	*$ 48*	*$ 48*	*$ 48*	*$ 47*	*$ 47*	*$ 47*	*$ 46*	*$ 46*	*$ 45*
Inflation and x-factor adjusted	*Nominal $/kW-year*	$ 51	$ 51	$ 51	$ 50	$ 50	$ 50	$ 49	$ 49	$ 49	$ 48	$ 48	$ 47	$ 48	$ 48	$ 48
Source		*NREL 2018 annual technology baseline mid-case (TRG-8)*														
WACC	*%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*
Source		*LEI assumption/ IRP2019*														
ITC	*%*	*30.0%*	*30.0%*	*30.0%*	*30.0%*	*30.0%*	*30.0%*	*30.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Economic life	*years*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*
Source		*IRP 2019*														
LCOE	*Nominal $/MWh*	$ 111	$ 112	$ 112	$ 114	$ 115	$ 116	$ 118	$ 161	$ 163	$ 165	$ 167	$ 169	$ 172	$ 174	$ 176
LCOE	*Nominal $/kW*	$ 324	$ 327	$ 330	$ 334	$ 338	$ 343	$ 347	$ 352	$ 356	$ 361	$ 366	$ 371	$ 376	$ 381	$ 387
CCGT																
Capital Cost	*$2018/kW*	*$ 1,029*	*$ 1,027*	*$ 1,026*	*$ 1,022*	*$ 1,018*	*$ 1,015*	*$ 1,009*	*$ 1,002*	*$ 995*	*$ 991*	*$ 987*	*$ 983*	*$ 979*	*$ 976*	*$ 972*
Puerto Rico cost adder	*%*	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Puerto Rico Capital Cost	*$2018/kW*	$ 1,193	$ 1,191	$ 1,190	$ 1,186	$ 1,181	$ 1,177	$ 1,171	$ 1,163	$ 1,154	$ 1,149	$ 1,145	$ 1,140	$ 1,136	$ 1,132	$ 1,128
Inflation adjusted	*Nominal $/kW*	$ 1,193	$ 1,199	$ 1,210	$ 1,223	$ 1,236	$ 1,251	$ 1,262	$ 1,273	$ 1,282	$ 1,296	$ 1,310	$ 1,324	$ 1,337	$ 1,351	$ 1,365
Source		*NREL 2018 annual technology baseline mid-case*														
Capacity Factor	*%*	*80%*	80 0%	80 0%	80 0%	80 0%	80 0%	80 0%	80 0%	80 0%	80 0%	80 0%	80 0%	80 0%	80 0%	80 0%
Fixed O&M	*$2018/kW-year*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*
Inflation and x-factor adjusted	*Nominal $/kW-year*	$ 10	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11
Variable O&M	*2018$/MWh*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*
Inflation and x-factor adjusted	*Nominal $/MWh*	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3
Source		*NREL 2018 annual technology baseline mid-case*														
WACC	*%*	*12.85%*	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%
Source		*LEI assumption/ IRP2019*														
Heat rate	*MMBtu/MWh*	*$ 6.4*	*$ 6.4*	*$ 6.4*	*$ 6.4*	*$ 6.4*	*$ 6.4*	*$ 6.4*	*$ 6.3*	*$ 6.3*	*$ 6.3*	*$ 6.3*	*$ 6.3*	*$ 6.3*	*$ 6.3*	*$ 6.3*
Fuel price	*$/MMBtu*	$ 8 0	$ 7 4	$ 7 8	$ 7 9	$ 8 0	$ 8 2	$ 8 3	$ 8 5	$ 8 6	$ 8 8	$ 9 0	$ 9 2	$ 9 4	$ 9 6	$ 9 8
Economic life	*years*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*
Source		*LEI assumption/ IRP2019*														
LCOE	*Nominal $/MWh*	$ 80	$ 76	$ 78	$ 79	$ 80	$ 82	$ 83	$ 84	$ 85	$ 86	$ 87	$ 89	$ 90	$ 92	$ 93
LCOE	*Nominal $/kW*	$ 179	$ 180	$ 181	$ 183	$ 185	$ 187	$ 189	$ 190	$ 191	$ 193	$ 195	$ 197	$ 199	$ 201	$ 203
Small CCGT																
Capital Cost	*$2018/kW*	*$ 1,658*	*$ 1,656*	*$ 1,653*	*$ 1,651*	*$ 1,648*	*$ 1,646*	*$ 1,643*	*$ 1,641*	*$ 1,638*	*$ 1,636*	*$ 1,633*	*$ 1,631*	*$ 1,628*	*$ 1,626*	*$ 1,624*
Puerto Rico cost adder	*%*	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Puerto Rico Capital Cost	*$2018/kW*	$ 1,923	$ 1,920	$ 1,918	$ 1,915	$ 1,912	$ 1,909	$ 1,906	$ 1,903	$ 1,900	$ 1,897	$ 1,895	$ 1,892	$ 1,889	$ 1,886	$ 1,883
Inflation adjusted	*Nominal $/kW*	$ 1,923	$ 1,932	$ 1,950	$ 1,975	$ 2,001	$ 2,028	$ 2,055	$ 2,083	$ 2,111	$ 2,140	$ 2,169	$ 2,196	$ 2,223	$ 2,251	$ 2,279
Source		*IRP 2019*														
Capacity Factor	*%*	*40%*	40 0%	40 0%	40 0%	40 0%	40 0%	40 0%	40 0%	40 0%	40 0%	40 0%	40 0%	40 0%	40 0%	40 0%
Fixed O&M	*$2018/kW-year*	*$ 36.1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*
Inflation and x-factor adjusted	*Nominal $/kW-year*	$ 36 1	$ 36 9	$ 36 9	$ 36 9	$ 36 9	$ 36 9	$ 36 9	$ 36 9	$ 36 9	$ 36 9	$ 36 9	$ 36 9	$ 37 2	$ 37 6	$ 38 0
Variable O&M	*2018$/MWh*	*$ 2.7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*
Inflation and x-factor adjusted	*Nominal $/MWh*	$ 2 7	$ 2 8	$ 2 8	$ 2 8	$ 2 8	$ 2 8	$ 2 8	$ 2 8	$ 2 8	$ 2 8	$ 2 8	$ 2 8	$ 2 8	$ 2 8	$ 2 9
Source		*NREL 2018 annual technology baseline mid-case*														
WACC	*%*	*12.85%*	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%
Source		*LEI assumption/ IRP2019*														
Heat rate	*MMBtu/MWh*	*$ 8.6*	*$ 8.6*	*$ 8.6*	*$ 8.5*	*$ 8.5*	*$ 8.5*	*$ 8.4*	*$ 8.4*	*$ 8.4*	*$ 8.2*	*$ 8.2*	*$ 8.2*	*$ 8.1*	*$ 8.1*	*$ 8.1*
Fuel price	*$/MMBtu*	$ 8 0	$ 7 4	$ 7 8	$ 7 9	$ 8 0	$ 8 2	$ 8 3	$ 8 5	$ 8 6	$ 8 8	$ 9 0	$ 9 2	$ 9 4	$ 9 6	$ 9 8
Economic life	*years*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*
Source		*LEI assumption/ IRP2019*														
LCOE	*Nominal $/MWh*	$ 159	$ 155	$ 159	$ 160	$ 162	$ 164	$ 166	$ 168	$ 171	$ 172	$ 175	$ 177	$ 179	$ 182	$ 185

Note: Assuming GE LM6000 parameters

PREPA Rate Forecast Model - Common Assumptions (3)

London Economics International LLC

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Battery Storage																
Capital cost	*$/kW*	*$ 2,550*	*$ 2,471*	*$ 2,394*	*$ 2,320*	*$ 2,248*	*$ 2,179*	*$ 2,111*	*$ 2,046*	*$ 1,982*	*$ 1,921*	*$ 1,861*	*$ 1,803*	*$ 1,748*	*$ 1,693*	*$ 1,641*
Puerto Rico cost adder	*%*	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Puerto Rico Capital Cost	*$2018/kW*	$ 2,958	$ 2,866	$ 2,777	$ 2,691	$ 2,608	$ 2,527	$ 2,449	$ 2,373	$ 2,299	$ 2,228	$ 2,159	$ 2,092	$ 2,027	$ 1,964	$ 1,903
Inflation adjusted	*Nominal $/kW*	$ 2,958	$ 2,883	$ 2,825	$ 2,776	$ 2,730	$ 2,685	$ 2,641	$ 2,597	$ 2,554	$ 2,512	$ 2,471	$ 2,428	$ 2,386	$ 2,344	$ 2,303
Fixed O&M	*$2018/kW-year*	*$ 9*	*$ 9*	*$ 9*	*$ 9*	*$ 8*	*$ 8*	*$ 8*	*$ 8*	*$ 8*	*$ 8*	*$ 8*	*$ 8*	*$ 8*	*$ 7*	*$ 7*
Inflation and x-factor adjusted	*Nominal $/kW-year*	$ 9	$ 9	$ 9	$ 9	$ 9	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8
Variable O&M	*2018$/MWh*	*$ 3*	*$ 3*	*$ 2*	*$ 2*	*$ 2*	*$ 2*	*$ 2*	*$ 2*	*$ 2*	*$ 2*	*$ 2*	*$ 2*	*$ 2*	*$ 2*	*$ 2*
Inflation and x-factor adjusted	*Nominal $/MWh*	$ 3	$ 3	$ 3	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2
Source		*Lazard levelized cost of storage analysis version 4.0, slide 40. Cost decline of 5% a year is based on section 6.5.3 in IRP 2019*														
WACC	*%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*
Source		*IRP 2019*														
Capacity Factor	%	*50%*	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
Source		*Based on 8 hour runtime*														
ITC	*%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Economic life	*years*	*15*	*15*	*15*	*15*	*15*	*15*	*15*	*15*	*15*	*15*	*15*	*15*	*15*	*15*	*15*
Source		*IRP 2019*														
LCOE	*Nominal $/MWh*	$ 108	$ 106	$ 104	$ 102	$ 100	$ 98	$ 97	$ 95	$ 94	$ 92	$ 90	$ 89	$ 87	$ 86	$ 84
LCOE	*Nominal $/kW*	$ 463	$ 452	$ 443	$ 435	$ 428	$ 421	$ 414	$ 407	$ 400	$ 394	$ 387	$ 381	$ 374	$ 368	$ 361
Recip engine																
Capital Cost	*$2018/kW*	*$ 1,761*	*$ 1,758*	*$ 1,755*	*$ 1,753*	*$ 1,750*	*$ 1,748*	*$ 1,745*	*$ 1,742*	*$ 1,740*	*$ 1,737*	*$ 1,735*	*$ 1,732*	*$ 1,729*	*$ 1,727*	*$ 1,724*
Source	*IRP 2019 page 133*															
Puerto Rico cost adder	*%*	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Puerto Rico Capital Cost	*$2018/kW*	$ 2,042	$ 2,039	$ 2,036	$ 2,033	$ 2,030	$ 2,027	$ 2,024	$ 2,021	$ 2,018	$ 2,015	$ 2,012	$ 2,009	$ 2,006	$ 2,003	$ 2,000
Inflation adjusted	*Nominal $/kW*	$ 2,042	$ 2,052	$ 2,071	$ 2,097	$ 2,125	$ 2,154	$ 2,183	$ 2,212	$ 2,242	$ 2,272	$ 2,303	$ 2,332	$ 2,361	$ 2,390	$ 2,420
Source		*IRP 2019*														
Capacity Factor	*%*	*6%*	5 8%	5 8%	5 8%	5 8%	5 8%	5 8%	5 8%	5 8%	5 8%	5 8%	5 8%	5 8%	5 8%	5 8%
Fixed O&M	*$2018/kW-year*	*$ 29*	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29
Inflation and x-factor adjusted	*Nominal $/kW-year*	$ 29	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30
Variable O&M	*2018$/MWh*	*$ 10*	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10
Inflation and x-factor adjusted	*Nominal $/MWh*	$ 10	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11
Source	*IRP 2019 page 132*															
WACC	*%*	*12.85%*	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%
Heat rate	*MMBtu/MWh*	*8.53*	*8.40*	*8.28*	*8.15*	*8.03*	*7.91*	*7.79*	*7.67*	*7.56*	*7.45*	*7.33*	*7.22*	*7.12*	*7.01*	*6.90*
Source	*IRP 2019 page 132*															
Fuel price	*$/MMBtu*	$ 8	$ 7	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 9	$ 9	$ 9	$ 9	$ 9	$ 10	$ 10
Economic life	*years*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*
Source		*LEI assumption/IRP2019*														
LCOE	*$/MWh*	$ 707	$ 704	$ 712	$ 719	$ 728	$ 736	$ 744	$ 752	$ 761	$ 770	$ 779	$ 787	$ 796	$ 805	$ 815
LCOE	*Nominal $/kW*	$ 317	$ 319	$ 322	$ 325	$ 329	$ 333	$ 338	$ 342	$ 346	$ 350	$ 354	$ 358	$ 363	$ 367	$ 372
Note: Assuming GE LM6000 parameters																
Recip engine for self generation																
Capital Cost	*$2018/kW*	*$ 1,612*	*$ 1,610*	*$ 1,607*	*$ 1,605*	*$ 1,602*	*$ 1,600*	*$ 1,598*	*$ 1,595*	*$ 1,593*	*$ 1,590*	*$ 1,588*	*$ 1,586*	*$ 1,583*	*$ 1,581*	*$ 1,578*
Source	*IRP 2019 page 133*															
Puerto Rico cost adder	*%*	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Puerto Rico Capital Cost	*$2018/kW*	$ 1,870	$ 1,867	$ 1,864	$ 1,862	$ 1,859	$ 1,856	$ 1,853	$ 1,850	$ 1,848	$ 1,845	$ 1,842	$ 1,839	$ 1,837	$ 1,834	$ 1,831
Inflation adjusted	*Nominal $/kW*	$ 1,870	$ 1,878	$ 1,896	$ 1,920	$ 1,946	$ 1,972	$ 1,998	$ 2,025	$ 2,053	$ 2,080	$ 2,108	$ 2,135	$ 2,161	$ 2,188	$ 2,216
Source		*IRP 2019*														
Capacity Factor	*%*	*50%*	50 0%	50 0%	50 0%	50 0%	50 0%	50 0%	50 0%	50 0%	50 0%	50 0%	50 0%	50 0%	50 0%	50 0%
Fixed O&M	*$2018/kW-year*	*$ 29*	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29
Inflation and x-factor adjusted	*Nominal $/kW-year*	$ 29	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30
Variable O&M	*2018$/MWh*	*$ 10*	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10
Inflation and x-factor adjusted	*Nominal $/MWh*	$ 10	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11
Source	*IRP 2019 page 132*															
WACC	*%*	*12.85%*	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%
Heat rate	*MMBtu/MWh*	*8.53*	*8.40*	*8.28*	*8.15*	*8.03*	*7.91*	*7.79*	*7.67*	*7.56*	*7.45*	*7.33*	*7.22*	*7.12*	*7.01*	*6.90*
Source	*IRP 2019 page 132*															
Fuel price	*$/MMBtu*	$ 8	$ 7	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 9	$ 9	$ 9	$ 9	$ 9	$ 10	$ 10
Economic life	*years*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*
Source		*LEI assumption/IRP2019*														
LCOE	*$/MWh*	$ 145	$ 140	$ 143	$ 144	$ 144	$ 145	$ 147	$ 148	$ 149	$ 150	$ 151	$ 152	$ 154	$ 155	$ 157
LCOE	*Nominal $/kW*	$ 293	$ 295	$ 297	$ 300	$ 304	$ 308	$ 311	$ 315	$ 319	$ 323	$ 327	$ 331	$ 335	$ 339	$ 343
LCOE for self generation (2x of the	*$/MWh*	$ 290	$ 279	$ 285	$ 287	$ 289	$ 291	$ 293	$ 295	$ 298	$ 300	$ 302	$ 305	$ 307	$ 310	$ 313
Note: Assuming GE LM6000 parameters																

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PREPA Rate Forecast Model - Common Assumptions (4)

London Economics International LLC

CHP for self generation		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Capital Cost	*$2018/kW*	$ 1,658	$ 1,656	$ 1,653	$ 1,651	$ 1,648	$ 1,646	$ 1,643	$ 1,641	$ 1,638	$ 1,636	$ 1,633	$ 1,631	$ 1,628	$ 1,626	$ 1,624
Puerto Rico cost adder	*%*	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Puerto Rico Capital Cost	*$2018/kW*	$ 1,923	$ 1,920	$ 1,918	$ 1,915	$ 1,912	$ 1,909	$ 1,906	$ 1,903	$ 1,900	$ 1,897	$ 1,895	$ 1,892	$ 1,889	$ 1,886	$ 1,883
Inflation adjusted	*Nominal $/kW*	$ 1,923	$ 1,932	$ 1,950	$ 1,975	$ 2,001	$ 2,028	$ 2,055	$ 2,083	$ 2,111	$ 2,140	$ 2,169	$ 2,196	$ 2,223	$ 2,251	$ 2,279
Source		*IRP 2019*														
Capacity Factor	*%*	*81%*	81 2%	81 2%	81 2%	81 2%	81 2%	81 2%	81 2%	81 2%	81 2%	81 2%	81 2%	81 2%	81 2%	81 2%
Fixed O&M	*$2018/kW-year*	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36
Inflation and x-factor adjusted	*Nominal $/kW-year*	$ 36	$ 37	$ 37	$ 37	$ 37	$ 37	$ 37	$ 37	$ 37	$ 37	$ 37	$ 37	$ 37	$ 38	$ 38
Variable O&M	*2018$/MWh*	$ 5	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3
Inflation and x-factor adjusted	*Nominal $/MWh*	$ 5	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3
Source		*NREL 2018 annual technology baseline mid-case*														
WACC	*%*	*12.85%*	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%
Source		*LEI assumption/IRP2019*														
Heat rate	*MMBtu/MWh*	*8.62*	*8.62*	*8.62*	*8.49*	*8.49*	*8.49*	*8.36*	*8.36*	*8.36*	*8.24*	*8.24*	*8.24*	*8.11*	*8.11*	*8.11*
Fuel price	*$/MMBtu*	$ 7 97	$ 7 36	$ 7 77	$ 7 90	$ 8 04	$ 8 18	$ 8 33	$ 8 49	$ 8 65	$ 8 81	$ 8 99	$ 9 17	$ 9 36	$ 9 55	$ 9 76
Economic life	*years*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*
Source		*LEI assumption/IRP2019*														
LCOE	*Nominal $/MWh*	$ 117	$ 110	$ 113	$ 113	$ 114	$ 115	$ 115	$ 117	$ 118	$ 118	$ 120	$ 121	$ 121	$ 123	$ 125
Note: Assuming GE LM6000 parameters																

Interim calculation for battery cost growth rate		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
CAGR (Battery capital cost)	%								-3 1%					-3 1%		
CAGR (Battery Fixed O&M)	%			-1 2%					-1 3%					-1 3%		
CAGR (Battery VOM)	%			-2 2%					-2 5%					-2 8%		

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PREPA Rate Forecast Model - Common assumptions cont.

London Economics International LLC

	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049
Baseline GNP forecast used I model	Real Millions US dollars	$ 57,552	$ 57,179	$ 57,071	$ 56,963	$ 56,856	$ 56,749	$ 56,420	$ 56,332	$ 56,244	$ 56,156	$ 56,068	$ 55,981	$ 55,945	$ 55,909	$ 55,873	$ 55,838	$ 55,802
GNP in CFP 2019	Real Millions US dollars																	
FOMB GNP forecast	Nominal Millions US dollars	$ 83,512	$ 84,298	$ 85,485	$ 86,690	$ 87,911	$ 89,149	$ 90,405	$ 92,069	$ 93,764	$ 95,489	$ 97,247	$ 99,037	$ 100,953	$ 102,906	$ 104,898	$ 106,927	$ 108,996
FOMB Inflation	%	1.40%	1.60%	1.60%	1.60%	1.60%	1.60%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
CAGR	%		1.41%					1.84%					1.93%					
FOMB Inflation index		1.23	1.25	1.27	1.29	1.31	1.33	1.35	1.38	1.41	1.44	1.47	1.50	1.53	1.56	1.59	1.62	1.65
Implied real static GNP		$ 68,063	$ 67,621	$ 67,494	$ 67,367	$ 67,240	$ 67,113	$ 66,724	$ 66,620	$ 66,516	$ 66,412	$ 66,308	$ 66,205	$ 66,162	$ 66,120	$ 66,078	$ 66,036	$ 65,993
Implied real GNP growth rate		0%	-1%	0%	0%	0%	0%	-1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
change	%	-0.45%	-0.65%	-0.19%	-0.19%	-0.19%	-0.19%	-0.28%	-0.21%	-0.21%	-0.21%	-0.22%	-0.23%	-0.22%	-0.22%	-0.22%		
Population	thousands of people	2,653	2,622	2,587	2,553	2,519	2,486	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453
CAGR	%		-1.32%					0.00%					0.00%					
Population (FOMB 2018)	thousands of people	2575	2541	2508	2476	2445	2414	2,383	2,351	2,321	2,290	2,260	2,230	2,201	2,172	2,144		
Source	FOMB fiscal plan 2019 (Certified May 9 2019)																	
change	%	-1.16%	-1.16%	-1.32%	-1.32%	-1.32%	-1.32%	-1.29%	-1.32%	-1.32%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%	-1.31%		
GNP per capital	Real US dollars	$ 21,696	$ 21,807	$ 22,058	$ 22,312	$ 22,569	$ 22,828	$ 23,000	$ 22,965	$ 22,929	$ 22,893	$ 22,857	$ 22,821	$ 22,807	$ 22,792	$ 22,778		
Inflation	%																	
Inflation adjustment factor		1.32	1.35	1.37	1.40	1.43	1.46	1.49	1.52	1.55	1.58	1.61	1.64	1.67	1.71	1.74		
General assumptions																		
WACC for new generation	%																	
WACC for transmission	%																	
Solar capacity factor	%																	
Wind capacity factor	%																	
Puerto Rico cost adder	%																	

LCOE summary	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Solar LCOE (Shown in IRP)	$/MWh	$ 71	$ 70	$ 70	$ 69	$ 68	$ 68	$ 68	$ 68	$ 68	$ 68	$ 68	$ 68	$ 68	$ 68	$ 68
Solar (Utility-Scale) LCOE (Calculated)	$/MWh	$ 91	$ 91	$ 92	$ 92	$ 93	$ 93	$ 94	$ 94	$ 95	$ 96	$ 97	$ 98	$ 98	$ 99	$ 100
Wind (Utility-Scale) LCOE (Calculated	$/MWh	$ 179	$ 182	$ 185	$ 188	$ 191	$ 194	$ 198	$ 202	$ 207	$ 211	$ 215	$ 220	$ 224	$ 229	$ 234
CCGT LCOE (Calculated)	$/MWh	$ 95	$ 97	$ 98	$ 100	$ 102	$ 104	$ 107	$ 109	$ 111	$ 114	$ 116	$ 119	$ 122	$ 124	$ 127
Small CCGT LCOE (Calculated)	$/MWh	$ 186	$ 190	$ 193	$ 195	$ 199	$ 202	$ 205	$ 210	$ 214	$ 217	$ 222	$ 227	$ 230	$ 235	$ 240
Battery Storage LCOE (Calculated)	$/MWh	$ 83	$ 82	$ 80	$ 79	$ 78	$ 77	$ 76	$ 75	$ 74	$ 73	$ 73	$ 72	$ 71	$ 71	$ 70
Solar (utility-scale)							-0 01187765									
Capital Cost	$2018/kW	$ 822	$ 812	$ 803	$ 793	$ 784	$ 775	$ 765	$ 756	$ 748	$ 739	$ 731	$ 723	$ 715	$ 707	$ 699
Puerto Rico cost adder	%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Puerto Rico Capital Cost	$2018/kW	$ 953	$ 942	$ 931	$ 920	$ 909	$ 899	$ 888	$ 877	$ 867	$ 858	$ 848	$ 839	$ 829	$ 820	$ 810
Inflation adjusted	Nominal $/kW	$ 1,170	$ 1,175	$ 1,180	$ 1,184	$ 1,189	$ 1,194	$ 1,203	$ 1,212	$ 1,222	$ 1,233	$ 1,244	$ 1,255	$ 1,265	$ 1,276	$ 1,286
				-1 1878%			-1 1878%									
Capacity Factor	%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%
Fixed O&M	$2018/kW-year	$ 10	$ 10	$ 10	$ 10	$ 9	$ 9	$ 9	$ 9	$ 9	$ 9	$ 9	$ 9	$ 9	$ 8	$ 8
Inflation and x-factor adjusted	Nominal $/kW-year	$ 10	$ 10	$ 10	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11
Source																
WACC	%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%
ITC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Economic life	years	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
LCOE	Nominal $/MWh	$ 91	$ 91	$ 92	$ 92	$ 93	$ 93	$ 94	$ 94	$ 95	$ 96	$ 97	$ 98	$ 98	$ 99	$ 100
LCOE	Nominal $/kW	$ 175	$ 176	$ 177	$ 178	$ 178	$ 179	$ 180	$ 182	$ 183	$ 185	$ 186	$ 188	$ 190	$ 191	$ 193

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PREPA Rate Forecast Model - Common assumptions (2) cont.

London Economics International LLC

	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Wind (utility-scale)																
Capital Cost	*$2018/kWdc*	*$ 1,714*	*$ 1,717*	*$ 1,721*	*$ 1,724*	*$ 1,728*	*$ 1,731*	*$ 1,735*	*$ 1,738*	*$ 1,742*	*$ 1,746*	*$ 1,749*	*$ 1,753*	*$ 1,757*	*$ 1,761*	*$ 1,765*
Puerto Rico cost adder	*%*	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Puerto Rico Capital Cost	*$2018/kW*	$ 1,988	$ 1,992	$ 1,996	$ 2,000	$ 2,004	$ 2,008	$ 2,012	$ 2,016	$ 2,021	$ 2,025	$ 2,029	$ 2,034	$ 2,038	$ 2,043	$ 2,048
Inflation adjusted	*Nominal $/kW*	$ 2,440	$ 2,483	$ 2,528	$ 2,574	$ 2,620	$ 2,667	$ 2,726	$ 2,787	$ 2,848	$ 2,912	$ 2,976	$ 3,042	$ 3,110	$ 3,180	$ 3,251
Capacity Factor	*%*	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Fixed O&M	*$2018/kW-year*	*$ 45*	*$ 45*	*$ 44*	*$ 44*	*$ 44*	*$ 43*	*$ 43*	*$ 42*	*$ 42*	*$ 42*	*$ 41*	*$ 41*	*$ 41*	*$ 40*	*$ 40*
Inflation and x-factor adjusted	*Nominal $/kW-year*	$ 48	$ 48	$ 48	$ 49	$ 49	$ 49	$ 49	$ 50	$ 51	$ 51	$ 52	$ 52	$ 53	$ 53	$ 54
WACC	*%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*	*12.8%*
ITC	*%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Economic life	*years*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*
LCOE	*Nominal $/MWh*	$ 179	$ 182	$ 185	$ 188	$ 191	$ 194	$ 198	$ 202	$ 207	$ 211	$ 215	$ 220	$ 224	$ 229	$ 234
LCOE	*Nominal $/kW*	$ 392	$ 398	$ 405	$ 412	$ 418	$ 425	$ 434	$ 443	$ 452	$ 462	$ 472	$ 481	$ 492	$ 502	$ 513
CCGT																
Capital Cost	*$2018/kW*	*$ 969*	*$ 965*	*$ 962*	*$ 960*	*$ 956*	*$ 952*	*$ 949*	*$ 945*	*$ 942*	*$ 939*	*$ 936*	*$ 933*	*$ 929*	*$ 925*	*$ 922*
Puerto Rico cost adder	*%*	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Puerto Rico Capital Cost	*$2018/kW*	$ 1,124	$ 1,119	$ 1,116	$ 1,113	$ 1,109	$ 1,105	$ 1,101	$ 1,097	$ 1,093	$ 1,089	$ 1,086	$ 1,082	$ 1,078	$ 1,073	$ 1,069
Inflation adjusted	*Nominal $/kW*	$ 1,379	$ 1,396	$ 1,413	$ 1,432	$ 1,450	$ 1,467	$ 1,491	$ 1,516	$ 1,541	$ 1,566	$ 1,593	$ 1,619	$ 1,645	$ 1,671	$ 1,697
Capacity Factor	*%*	80 0%	80 0%	80 0%	80 0%	80 0%	80 0%	80 0%	80 0%	80 0%	80 0%	80 0%	80 0%	80 0%	80 0%	80 0%
Fixed O&M	*$2018/kW-year*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*	*$ 10*
Inflation and x-factor adjusted	*Nominal $/kW-year*	$ 11	$ 11	$ 11	$ 11	$ 12	$ 12	$ 12	$ 12	$ 12	$ 13	$ 13	$ 13	$ 14	$ 14	$ 14
Variable O&M	*2018$/MWh*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*	*$ 3*
Inflation and x-factor adjusted	*Nominal $/MWh*	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 4	$ 4	$ 4
WACC	*%*	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%
Heat rate	*MMBtu/MWh*	*$ 6.3*	*$ 6.3*	*$ 6.3*	*$ 6.3*	*$ 6.3*	*$ 6.3*	*$ 6.3*	*$ 6.3*	*$ 6.3*	*$ 6.3*	*$ 6.3*	*$ 6.3*	*$ 6.3*	*$ 6.3*	*$ 6.3*
Fuel price	*$/MMBtu*	$ 10 0	$ 10 2	$ 10 4	$ 10 6	$ 10 9	$ 11 1	$ 11 4	$ 11 7	$ 12 0	$ 12 3	$ 12 6	$ 12 9	$ 13 2	$ 13 6	$ 13 9
Economic life	*years*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*
LCOE	*Nominal $/MWh*	$ 95	$ 97	$ 98	$ 100	$ 102	$ 104	$ 107	$ 109	$ 111	$ 114	$ 116	$ 119	$ 122	$ 124	$ 127
LCOE	*Nominal $/kW*	$ 206	$ 208	$ 211	$ 214	$ 216	$ 219	$ 222	$ 226	$ 230	$ 234	$ 238	$ 242	$ 246	$ 249	$ 254
Small CCGT																
Capital Cost	*$2018/kW*	*$ 1,621*	*$ 1,619*	*$ 1,616*	*$ 1,614*	*$ 1,611*	*$ 1,609*	*$ 1,607*	*$ 1,604*	*$ 1,602*	*$ 1,599*	*$ 1,597*	*$ 1,595*	*$ 1,592*	*$ 1,590*	*$ 1,587*
Puerto Rico cost adder	*%*	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Puerto Rico Capital Cost	*$2018/kW*	$ 1,880	$ 1,878	$ 1,875	$ 1,872	$ 1,869	$ 1,866	$ 1,864	$ 1,861	$ 1,858	$ 1,855	$ 1,852	$ 1,850	$ 1,847	$ 1,844	$ 1,841
Inflation adjusted	*Nominal $/kW*	$ 2,307	$ 2,341	$ 2,375	$ 2,409	$ 2,444	$ 2,479	$ 2,525	$ 2,572	$ 2,619	$ 2,668	$ 2,717	$ 2,767	$ 2,818	$ 2,870	$ 2,923
Capacity Factor	*%*	40 0%	40 0%	40 0%	40 0%	40 0%	40 0%	40 0%	40 0%	40 0%	40 0%	40 0%	40 0%	40 0%	40 0%	40 0%
Fixed O&M	*$2018/kW-year*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*	*$ 36 1*
Inflation and x-factor adjusted	*Nominal $/kW-year*	$ 38 3	$ 38 7	$ 39 3	$ 39 9	$ 40 5	$ 41 1	$ 41 7	$ 42 6	$ 43 4	$ 44 3	$ 45 2	$ 46 1	$ 47 0	$ 47 9	$ 48 9
Variable O&M	*2018$/MWh*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*	*$ 2 7*
Inflation and x-factor adjusted	*Nominal $/MWh*	$ 2 9	$ 2 9	$ 3 0	$ 3 0	$ 3 1	$ 3 1	$ 3 1	$ 3 2	$ 3 3	$ 3 3	$ 3 4	$ 3 5	$ 3 5	$ 3 6	$ 3 7
WACC	*%*	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%
Heat rate	*MMBtu/MWh*	*$ 8.0*	*$ 8.0*	*$ 8.0*	*$ 7.9*	*$ 7.9*	*$ 7.9*	*$ 7.8*	*$ 7.8*	*$ 7.8*	*$ 7.6*	*$ 7.6*	*$ 7.6*	*$ 7.5*	*$ 7.5*	*$ 7.5*
Fuel price	*$/MMBtu*	$ 10 0	$ 10 2	$ 10 4	$ 10 6	$ 10 9	$ 11 1	$ 11 4	$ 11 7	$ 12 0	$ 12 3	$ 12 6	$ 12 9	$ 13 2	$ 13 6	$ 13 9
Economic life	*years*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*
LCOE	*Nominal $/MWh*	$ 186	$ 190	$ 193	$ 195	$ 199	$ 202	$ 205	$ 210	$ 214	$ 217	$ 222	$ 227	$ 230	$ 235	$ 240

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PREPA Rate Forecast Model - Common assumptions (3) cont.

London Economics International LLC

		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Battery Storage																
Capital cost	$/kW	$ 1,590	$ 1,541	$ 1,493	$ 1,447	$ 1,402	$ 1,358	$ 1,316	$ 1,275	$ 1,236	$ 1,198	$ 1,160	$ 1,124	$ 1,090	$ 1,056	$ 1,023
Puerto Rico cost adder	%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Puerto Rico Capital Cost	$2018/kW	$ 1,844	$ 1,787	$ 1,732	$ 1,678	$ 1,626	$ 1,576	$ 1,527	$ 1,480	$ 1,434	$ 1,389	$ 1,346	$ 1,304	$ 1,264	$ 1,225	$ 1,187
Inflation adjusted	Nominal $/kW	$ 2,263	$ 2,228	$ 2,193	$ 2,159	$ 2,126	$ 2,093	$ 2,069	$ 2,045	$ 2,021	$ 1,997	$ 1,974	$ 1,951	$ 1,929	$ 1,906	$ 1,884
Fixed O&M	$2018/kW-year	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7
Inflation and x-factor adjusted	Nominal $/kW-year	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 9	$ 9
Variable O&M	2018$/MWh	$ 2	$ 2	$ 2	$ 2	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1
Inflation and x-factor adjusted	Nominal $/MWh	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2
WACC	%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%	12.8%
Capacity Factor	%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
ITC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Economic life	years	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
LCOE	Nominal $/MWh	$ 83	$ 82	$ 80	$ 79	$ 78	$ 77	$ 76	$ 75	$ 74	$ 73	$ 73	$ 72	$ 71	$ 71	$ 70
LCOE	Nominal $/kW	$ 355	$ 350	$ 344	$ 339	$ 334	$ 329	$ 325	$ 322	$ 318	$ 315	$ 311	$ 308	$ 305	$ 301	$ 298
Recip engine																
Capital Cost	$2018/kW	$ 1,722	$ 1,719	$ 1,716	$ 1,714	$ 1,711	$ 1,709	$ 1,706	$ 1,704	$ 1,701	$ 1,698	$ 1,696	$ 1,693	$ 1,691	$ 1,688	$ 1,686
Puerto Rico cost adder	%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Puerto Rico Capital Cost	$2018/kW	$ 1,997	$ 1,994	$ 1,991	$ 1,988	$ 1,985	$ 1,982	$ 1,979	$ 1,976	$ 1,973	$ 1,970	$ 1,967	$ 1,964	$ 1,961	$ 1,958	$ 1,955
Inflation adjusted	Nominal $/kW	$ 2,450	$ 2,486	$ 2,522	$ 2,558	$ 2,595	$ 2,633	$ 2,681	$ 2,731	$ 2,781	$ 2,833	$ 2,885	$ 2,938	$ 2,993	$ 3,048	$ 3,104
Capacity Factor	%	5 8%	5 8%	5 8%	5 8%	5 8%	5 8%	5 8%	5 8%	5 8%	5 8%	5 8%	5 8%	5 8%	5 8%	5 8%
Fixed O&M	$2018/kW-year	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29
Inflation and x-factor adjusted	Nominal $/kW-year	$ 31	$ 31	$ 32	$ 32	$ 32	$ 33	$ 33	$ 34	$ 35	$ 36	$ 36	$ 37	$ 38	$ 38	$ 39
Variable O&M	2018$/MWh	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10
Inflation and x-factor adjusted	Nominal $/MWh	$ 11	$ 11	$ 11	$ 11	$ 12	$ 12	$ 12	$ 12	$ 12	$ 13	$ 13	$ 13	$ 13	$ 14	$ 14
WACC	%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%
Heat rate	MMBtu/MWh	6.80	6.70	6.60	6.50	6.40	6.30	6.21	6.12	6.03	5.93	5.85	5.76	5.67	5.59	5.50
Fuel price	$/MMBtu	$ 10	$ 10	$ 10	$ 11	$ 11	$ 11	$ 11	$ 12	$ 12	$ 12	$ 13	$ 13	$ 13	$ 14	$ 14
Economic life	years	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
LCOE	$/MWh	$ 824	$ 835	$ 847	$ 859	$ 871	$ 883	$ 898	$ 914	$ 931	$ 948	$ 965	$ 982	$ 1,000	$ 1,018	$ 1,036
LCOE	Nominal $/kW	$ 376	$ 382	$ 387	$ 393	$ 399	$ 404	$ 412	$ 419	$ 427	$ 435	$ 443	$ 451	$ 460	$ 468	$ 477
Recip engine for self generation																
Capital Cost	$2018/kW	$ 1,576	$ 1,574	$ 1,571	$ 1,569	$ 1,567	$ 1,564	$ 1,562	$ 1,560	$ 1,557	$ 1,555	$ 1,553	$ 1,550	$ 1,548	$ 1,546	$ 1,543
Puerto Rico cost adder	%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Puerto Rico Capital Cost	$2018/kW	$ 1,828	$ 1,826	$ 1,823	$ 1,820	$ 1,817	$ 1,815	$ 1,812	$ 1,809	$ 1,806	$ 1,804	$ 1,801	$ 1,798	$ 1,796	$ 1,793	$ 1,790
Inflation adjusted	Nominal $/kW	$ 2,243	$ 2,276	$ 2,309	$ 2,342	$ 2,376	$ 2,410	$ 2,455	$ 2,500	$ 2,546	$ 2,593	$ 2,641	$ 2,690	$ 2,740	$ 2,790	$ 2,842
Capacity Factor	%	50 0%	50 0%	50 0%	50 0%	50 0%	50 0%	50 0%	50 0%	50 0%	50 0%	50 0%	50 0%	50 0%	50 0%	50 0%
Fixed O&M	$2018/kW-year	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29
Inflation and x-factor adjusted	Nominal $/kW-year	$ 31	$ 31	$ 32	$ 32	$ 32	$ 33	$ 33	$ 34	$ 35	$ 36	$ 36	$ 37	$ 38	$ 38	$ 39
Variable O&M	2018$/MWh	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10
Inflation and x-factor adjusted	Nominal $/MWh	$ 11	$ 11	$ 11	$ 11	$ 12	$ 12	$ 12	$ 12	$ 12	$ 13	$ 13	$ 13	$ 13	$ 14	$ 14
WACC	%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%
Heat rate	MMBtu/MWh	6.80	6.70	6.60	6.50	6.40	6.30	6.21	6.12	6.03	5.93	5.85	5.76	5.67	5.59	5.50
Fuel price	$/MMBtu	$ 10	$ 10	$ 10	$ 11	$ 11	$ 11	$ 11	$ 12	$ 12	$ 12	$ 13	$ 13	$ 13	$ 14	$ 14
Economic life	years	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
LCOE	$/MWh	$ 158	$ 160	$ 161	$ 163	$ 165	$ 167	$ 170	$ 172	$ 175	$ 177	$ 180	$ 183	$ 185	$ 188	$ 191
LCOE	Nominal $/kW	$ 347	$ 352	$ 357	$ 362	$ 368	$ 373	$ 380	$ 387	$ 394	$ 401	$ 409	$ 416	$ 424	$ 432	$ 440
LCOE for self generation (2x of the	$/MWh	$ 316	$ 319	$ 323	$ 327	$ 331	$ 334	$ 339	$ 344	$ 349	$ 354	$ 360	$ 365	$ 371	$ 376	$ 382

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PREPA Rate Forecast Model - Common assumptions (4) cont.

London Economics International LLC

Battery Storage		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Capital Cost	$2018/kW	$ 1,621	$ 1,619	$ 1,616	$ 1,614	$ 1,611	$ 1,609	$ 1,607	$ 1,604	$ 1,602	$ 1,599	$ 1,597	$ 1,595	$ 1,592	$ 1,590	$ 1,587
Puerto Rico cost adder	%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Puerto Rico Capital Cost	$2018/kW	$ 1,880	$ 1,878	$ 1,875	$ 1,872	$ 1,869	$ 1,866	$ 1,864	$ 1,861	$ 1,858	$ 1,855	$ 1,852	$ 1,850	$ 1,847	$ 1,844	$ 1,841
Inflation adjusted	Nominal $/kW	$ 2,307	$ 2,341	$ 2,375	$ 2,409	$ 2,444	$ 2,479	$ 2,525	$ 2,572	$ 2,619	$ 2,668	$ 2,717	$ 2,767	$ 2,818	$ 2,870	$ 2,923
Capacity Factor	%	81 2%	81 2%	81 2%	81 2%	81 2%	81 2%	81 2%	81 2%	81 2%	81 2%	81 2%	81 2%	81 2%	81 2%	81 2%
Fixed O&M	$2018/kW-year	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36	$ 36
Inflation and x-factor adjusted	Nominal $/kW-year	$ 38	$ 39	$ 39	$ 40	$ 41	$ 41	$ 42	$ 43	$ 43	$ 44	$ 45	$ 46	$ 47	$ 48	$ 49
Variable O&M	2018$/MWh	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3
Inflation and x-factor adjusted	Nominal $/MWh	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 4	$ 4	$ 4
WACC	%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%	12 85%
Heat rate	MMBtu/MWh	7.99	7.99	7.99	7.87	7.87	7.87	7.75	7.75	7.75	7.64	7.64	7.64	7.52	7.52	7.52
Fuel price	$/MMBtu	$ 9 97	$ 10 18	$ 10 41	$ 10 65	$ 10 89	$ 11 15	$ 11 41	$ 11 69	$ 11 98	$ 12 27	$ 12 58	$ 12 90	$ 13 24	$ 13 58	$ 13 94
Economic life	years	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
LCOE	Nominal $/MWh	$ 125	$ 127	$ 129	$ 130	$ 132	$ 134	$ 134	$ 137	$ 139	$ 140	$ 143	$ 145	$ 146	$ 149	$ 152

Interim calculation for battery cost growth rate		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
CAGR (Battery capital cost)	%			-3 1%					-3 1%					-3 1%		
CAGR (Battery Fixed O&M)	%			-1 4%					-1 6%					0 0%		
CAGR (Battery VOM)	%			-3 3%					-4 0%					0 0%		

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PREPA Rate Forecast Model - Costs - Total

London Economics International LLC

	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total cost (excl. pension)			**$ 3,194**	**$ 3,883**	**$ 3,660**	**$ 3,129**	**$ 3,168**	**$ 3,137**	**$ 2,905**	**$ 2,935**	**$ 2,973**	**$ 3,045**	**$ 3,251**	**$ 3,493**	**$ 3,719**	**$ 3,933**
Total cost (incl. pension)			**$ 3,194**	**$ 4,104**	**$ 3,888**	**$ 3,356**	**$ 3,393**	**$ 3,361**	**$ 3,111**	**$ 3,140**	**$ 3,177**	**$ 3,248**	**$ 3,452**	**$ 3,693**	**$ 3,918**	**$ 4,130**
CILT and subsidies	*Nominal Millions US dollars*		$ 278	$ 274	$ 271	$ 268	$ 264	$ 261	$ 259	$ 256	$ 254	$ 251	$ 249	$ 247	$ 245	$ 243
Labor and Operations (without Pension)	*Nominal Millions US dollars*		$ 697	$ 1,132	$ 1,088	$ 1,100	$ 1,117	$ 1,138	$ 1,172	$ 1,152	$ 1,170	$ 1,175	$ 1,183	$ 1,195	$ 1,206	$ 1,214
Labor and Operations (incl. pension)	*Nominal Millions US dollars*		$ 697	$ 1,354	$ 1,316	$ 1,327	$ 1,342	$ 1,362	$ 1,379	$ 1,358	$ 1,374	$ 1,378	$ 1,385	$ 1,395	$ 1,405	$ 1,411
Cost of T&D capex	*Nominal Millions US dollars*		$ -	$ 157	$ 167	$ 176	$ 186	$ 198	$ 85	$ 103	$ 122	$ 140	$ 159	$ 408	$ 656	$ 905
Fuel and purchased power	*Nominal Millions US dollars*		$ 2,219	$ 2,319	$ 2,135	$ 1,585	$ 1,601	$ 1,540	$ 1,389	$ 1,423	$ 1,428	$ 1,479	$ 1,660	$ 1,644	$ 1,611	$ 1,571

LEI reclassified to separate GenCo costs from Transmission and Distribution (GridCo) costs	2018	2019	2020	2021	2022	2023	2024
Total cost		**$ 3,194**	**$ 3,883**	**$ 3,660**	**$ 3,129**	**$ 3,168**	**$ 3,137**
CILT and subsidies		$ 278	$ 274	$ 271	$ 268	$ 264	$ 261
Labor and Operations		$ 377	$ 858	$ 899	$ 907	$ 916	$ 933
Cost of non-gen capex		$ -	$ 157	$ 167	$ 176	$ 186	$ 198
Fuel and purchased power		$ 2,539	$ 2,593	$ 2,323	$ 1,778	$ 1,802	$ 1,745

Cerfified Fiscal Plan 2019	unit	2018	2019	2020	2021	2022	2023	2024
CILT and subsidies	*Nominal Millions US dollars*		$ 274	$ 297	$ 282	$ 271	$ 259	$ 254
Labor and Operations	*Nominal Millions US dollars*		$ 697	$ 1,074	$ 898	$ 893	$ 895	$ 903
Maintenance expenses	*Nominal Millions US dollars*			$ 27	$ 82	$ 82	$ 82	$ 82
Fuel and purchased power	*Nominal Millions US dollars*		$ 2,038	$ 1,897	$ 1,835	$ 1,810	$ 1,704	$ 1,682
Bad debt	*Nominal Millions US dollars*			$ 62	$ 62	$ 62	$ 62	$ 62
Total	*Nominal Millions US dollars*		**$ 3,009**	**$ 3,357**	**$ 3,159**	**$ 3,118**	**$ 3,002**	**$ 2,983**

LEI re-classified vs Fiscal Plan (to be comparable with CFP2019)		2018	2019	2020	2021	2022	2023	2024
CILT and subsidies	*Nominal Millions US dollars*			$ (23)	$ (11)	$ (3)	$ 5	$ 7
Labor and Operations	*Nominal Millions US dollars*			$ (216)	$ 1	$ 14	$ 21	$ 30
Cost of non-gen capex	*Nominal Millions US dollars*			$ 130	$ 85	$ 94	$ 104	$ 116
Fuel and purchased power	*Nominal Millions US dollars*			$ 696	$ 488	$ (32)	$ 98	$ 63

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PREPA Rate Forecast Model - Cost - Total cont.

London Economics International LLC

	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total cost (excl. pension)		**$ 4,152**	**$ 4,371**	**$ 4,595**	**$ 4,571**	**$ 4,546**	**$ 4,527**	**$ 4,523**	**$ 4,510**	**$ 4,556**	**$ 4,560**	**$ 4,564**	**$ 4,568**	**$ 4,551**	**$ 4,532**	**$ 4,538**
Total cost (incl. pension)		**$ 4,348**	**$ 4,566**	**$ 4,788**	**$ 4,762**	**$ 4,736**	**$ 4,716**	**$ 4,712**	**$ 4,699**	**$ 4,744**	**$ 4,748**	**$ 4,752**	**$ 4,757**	**$ 4,740**	**$ 4,721**	**$ 4,727**
CILT and subsidies	*Nominal Millions US dollars*	$ 241	$ 239	$ 237	$ 236	$ 234	$ 233	$ 231	$ 230	$ 229	$ 228	$ 227	$ 226	$ 225	$ 224	$ 223
Labor and Operations (without Pension)	*Nominal Millions US dollars*	$ 1,226	$ 1,239	$ 1,251	$ 1,264	$ 1,279	$ 1,298	$ 1,316	$ 1,320	$ 1,381	$ 1,399	$ 1,421	$ 1,442	$ 1,443	$ 1,443	$ 1,468
Labor and Operations (incl. pension)	*Nominal Millions US dollars*	$ 1,422	$ 1,433	$ 1,444	$ 1,456	$ 1,470	$ 1,486	$ 1,505	$ 1,508	$ 1,569	$ 1,588	$ 1,609	$ 1,631	$ 1,632	$ 1,632	$ 1,656
Cost of T&D capex	*Nominal Millions US dollars*	$ 1,154	$ 1,403	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652
Fuel and purchased power	*Nominal Millions US dollars*	$ 1,530	$ 1,490	$ 1,454	$ 1,419	$ 1,381	$ 1,345	$ 1,324	$ 1,308	$ 1,294	$ 1,281	$ 1,265	$ 1,248	$ 1,232	$ 1,214	$ 1,196

PREPA Rate Forecast Model - Cost - Labor and Operations

London Economics International LLC

$ million	Calculation	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Labor and operations	**Sum**		$0	$697	$1,132	$1,088	$1,100	$1,117	$1,138	$1,172	$1,152	$1,170	$1,175	$1,183	$1,195	$1,206	$1,214
Pension	**Pension rates*demand**	$ million	$0	$0	$222	$228	$227	$225	$224	$207	$206	$204	$203	$201	$200	$199	$197
PREPA ERS Pension Charge (not using; show as benchmark as the number is too high now)	CFP 2019 slide 55 until 2024, CFP 2018 excel model from 2025 to 2038	$ million				$228	$227	$225	$224	$207	$206	$204	$203	$201	$200	$199	$197
Demand used to forecast Pension rates	CFP 2019 slide 57	Gwh	13,302	15,764	15,832	14,772	13,972	13,491	13,150	12,818	12,494	12,178	11,870	11,570	11,278	10,993	10,715
				19%	0%	-7%	-5%	-3%	-3%								
Pension rates	CFP 2019 slide 87	$/MWh			14.00	16.00	16.00	17.00	17.00	17.00	18.00	19.00	20.00	21.00	23.00	24.00	26.00
Recurring capex for existing generation		$ million	$0	$0	$31	$38	$47	$55	$63	$72	$81	$89	$85	$84	$86	$89	$90
ST capex		$ million	$46	$29	$13	$11	$11	$9	$10	$0	$0	$0	$0	$0	$0	$0	$0
Capex on ST		$/kW-year	$19.68	$20.07	$20.47	$20.88	$21.30	$21.72	$22.16	$22.60	$23.05	$23.52	$23.99	$24.47	$24.95	$25.45	$25.96
Capacity of ST	excluded AES coal	kW	2,352,000	1,452,000	632,000	532,000	532,000	432,000	432,000	-	-	-	-	-	-	-	-
CC capex		$ million	$11	$11	$12	$12	$12	$12	$13	$24	$24	$25	$25	$26	$26	$27	$27
Capex on CC		$/kW-year	$27.15	$27.70	$28.25	$28.82	$29.39	$29.98	$30.58	$31.19	$31.82	$32.45	$33.10	$33.76	$34.44	$35.13	$35.83
Capacity of CC	excluded ecoelectrica	kW	413,000	413,000	413,000	413,000	413,000	413,000	413,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000
GT capex		$ million	$15	$16	$16	$17	$22	$22	$23	$23	$24	$24	$25	$25	$26	$26	$27
Capex on GT		$/kW-year	$20.66	$21.08	$21.50	$21.93	$22.37	$22.81	$23.27	$23.74	$24.21	$24.69	$25.19	$25.69	$26.21	$26.73	$27.26
Capacity of GT		kW	744,000	744,000	744,000	784,000	984,000	984,000	984,000	984,000	984,000	984,000	984,000	984,000	984,000	984,000	984,000
Wind capex		$ million	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capex on Wind		$/kW-year	$19.18	$19.56	$19.95	$20.35	$20.76	$21.17	$21.59	$22.03	$22.47	$22.92	$23.38	$23.84	$24.32	$24.81	$25.30
Capacity of Wind		kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar capex		$ million	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capex on Solar		$/kW-year	$33.76	$34.43	$35.12	$35.82	$36.54	$37.27	$38.02	$38.78	$39.55	$40.34	$41.15	$41.97	$42.81	$43.67	$44.54
Capacity on Solar		kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydro capex		$ million	$1	$1	$1	$1	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Capex on Hydro		$/kW-year	$40.52	$41.33	$42.16	$43.00	$43.86	$44.74	$45.63	$46.55	$47.48	$48.43	$49.39	$50.38	$51.39	$52.42	$53.47
Capacity on Hydro		kW	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000
Total annual recurring capex for thermal			$ 73	$ 56	$ 41	$ 40	$ 45	$ 44	$ 45	$ 47	$ 48	$ 49	$ 50	$ 51	$ 52	$ 53	$ 54
Total annual recurring capex for renewables			$ 1	$ 1	$ 1	$ 1	$ 1	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2
Thermal capex amortization years	10																
Renewable capex amortization years	20																

Thermal capex amortization table	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
2018	$ million	$ 13	$ 13	$ 13	$ 13	$ 13	$ 13	$ 13	$ 13	$ 13	$ 13					
2019	$ million		$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10				
2020	$ million			$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7			
2021	$ million				$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7		
2022	$ million					$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	
2023	$ million						$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8
2024	$ million							$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8
2025	$ million								$ 9	$ 9	$ 9	$ 9	$ 9	$ 9	$ 9	$ 9
2026	$ million									$ 9	$ 9	$ 9	$ 9	$ 9	$ 9	$ 9
2027	$ million										$ 9	$ 9	$ 9	$ 9	$ 9	$ 9
2028	$ million											$ 9	$ 9	$ 9	$ 9	$ 9
2029	$ million												$ 9	$ 9	$ 9	$ 9
2030	$ million													$ 9	$ 9	$ 9
2031	$ million														$ 10	$ 10
2032	$ million															$ 10
2033	$ million															
2034	$ million															
2035	$ million															
2036	$ million															
2037	$ million															
2038	$ million															
2039	$ million															
2040	$ million															
2041	$ million															
2042	$ million															
2043	$ million															
2044	$ million															
2045	$ million															
2046	$ million															
2047	$ million															
Total	$ million	**$ 13**	**$ 24**	**$ 31**	**$ 38**	**$ 47**	**$ 55**	**$ 63**	**$ 72**	**$ 81**	**$ 89**	**$ 85**	**$ 84**	**$ 86**	**$ 89**	**$ 90**

Confidential

PREPA Rate Forecast Model - Cost - Labor and Operations (2)

London Economics International LLC

Renewables capex amortization table		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
2018	$ million	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2019	$ million		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2020	$ million			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2021	$ million				$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2022	$ million					$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2023	$ million						$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2024	$ million							$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2025	$ million								$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2026	$ million									$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2027	$ million										$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2028	$ million											$ 0	$ 0	$ 0	$ 0	$ 0
2029	$ million												$ 0	$ 0	$ 0	$ 0
2030	$ million													$ 0	$ 0	$ 0
2031	$ million														$ 0	$ 0
2032	$ million															$ 0
2033	$ million															
2034	$ million															
2035	$ million															
2036	$ million															
2037	$ million															
2038	$ million															
2039	$ million															
2040	$ million															
2041	$ million															
2042	$ million															
2043	$ million															
2044	$ million															
2045	$ million															
2046	$ million															
2047	$ million															
Total	$ million	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
O&M Generation		$ million		$ 320	$ 243	$ 150	$ 146	$ 146	$ 142	$ 142	$ 95	$ 95	$ 95	$ 95	$ 95	$ 95	$ 96
Labor operating	initial from CFP2019 slide 70	$ million		$ 205	$ 77	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79
Non-labor/other operating	initial from CFP2019 slide 70	$ million			$ 80	$ 82	$ 82	$ 82	$ 82	$ 82	$ 82	$ 82	$ 82	$ 82	$ 82	$ 82	$ 82
Necessary maintenance	initial from CFP2019 slide 70	$ million		$ 115	$ 86	$ 88	$ 88	$ 88	$ 88	$ 88	$ 88	$ 88	$ 88	$ 88	$ 88	$ 88	$ 89
Take out retired units	based on IRP 2019	$ million		$ -	$ -	$ (97)	$ (102)	$ (102)	$ (106)	$ (106)	$ (152)	$ (152)	$ (152)	$ (152)	$ (152)	$ (152)	$ (154)
O&M T&D		$ million		$ 377	$ 858	$ 899	$ 907	$ 916	$ 933	$ 959	$ 976	$ 985	$ 994	$ 1,004	$ 1,013	$ 1,022	$ 1,027
Labor operating - without concessionaire		$ million		$ -	$ 327	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Non-labor/other operating - without concessionaire		$ million		$ 377	$ 394	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Necessary maintenance - without concessionaire		$ million			$ 137	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Labor T&D with concessionaire		$ million		$ -	$ -	$ 334	$ 337	$ 340	$ 347	$ 354	$ 361	$ 365	$ 368	$ 372	$ 376	$ 379	$ 383
Non-labor/other operating - with concessionaire		$ million		$ -	$ -	$ 352	$ 355	$ 359	$ 366	$ 373	$ 381	$ 385	$ 389	$ 392	$ 396	$ 400	$ 404
Necessary maintenance - with concessionaire		$ million		$ -	$ -	$ 140	$ 141	$ 143	$ 145	$ 148	$ 151	$ 153	$ 154	$ 156	$ 157	$ 159	$ 161
Bonus to concessionaire		$ million				$ -	$ -	$ -	$ -	$ 4	$ 4	$ 5	$ 5	$ 5	$ 5	$ 5	$ 2
Concessionaire profit margin		$ million				$ 74	$ 74	$ 74	$ 74	$ 78	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ 76
Concessionaire profit margin	annual value	$ million				$ 64	$ 64	$ 96	$ 112	$ 134	$ 156	$ 178	$ 198	$ 219	$ 247	$ 275	$ 302
Concessionaire profit margin	20 year average					$ 74	$ 74	$ 74	$ 74	$ 74	$ 74	$ 74	$ 74	$ 74	$ 74	$ 74	$ 74
T&D asset base		$ million		$ 1,950	$ 3,111	$ 4,243	$ 5,347	$ 6,424	$ 7,473	$ 8,966	$ 10,422	$ 11,842	$ 13,226	$ 14,575	$ 16,477	$ 18,332	$ 20,140
Concessionaire profit margin as	% of the T&D asset base		1.5%														
trends for existing generation	inflation - X factor	%	2.00%	2.00%	2.00%	2.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.00%
trends for T&D	inflation - X factor	%	2.00%	2.00%	2.00%	2.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.50%
trends for existing generation factor		index			1.00	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.03
trends for T&D factor		index			1.00	1.02	1.03	1.04	1.05	1.06	1.07	1.08	1.09	1.10	1.12	1.13	1.14
X factor for Generation	Average efficiency gains YoY in Generation table below		0.00%	0.00%	0.00%	0.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	1.00%
X factor for T&D	Average efficiency gains YoY in Wires table below		0.00%	0.00%	0.00%	0.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	0.50%

Recurring capex by technology based on FERC Form 1 data	Average ($/kW-month)
Solar	2.70
Gas Turbine	1.66
Hydraulic Turbine	3.25
Steam Turbine	1.58
Combined Cycle	2.17
Wind Turbine	1.54

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PREPA Rate Forecast Model - Cost - Labor and Operations cont.

London Economics International LLC

$ million	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total Labor and operations		$1,226	$1,239	$1,251	$1,264	$1,279	$1,298	$1,316	$1,320	$1,381	$1,399	$1,421	$1,442	$1,443	$1,443	$1,468
Pension	$ million	$196	$194	$193	$192	$190	$189	$189	$189	$189	$189	$189	$189	$189	$189	$189
PREPA ERS Pension Charge (not using; show as benchmark as the number is too high now)	$ million	$196	$194	$193	$192	$190	$189									
Demand used to forecast Pension rates	Gwh	10,444	10,180	$10,180	$10,180	$10,180	$10,180	$10,180	$10,180	$10,180	$10,180	$10,180	$10,180	$10,180	$10,180	$10,180
Pension rates	$/MWh	28.00	31.00	$31	$31	$31	$31	$31	$31	$31	$31	$31	$31	$31	$31	$31
Recurring capex for existing generation	$ million	$92	$94	$96	$98	$100	$101	$103	$103	$104	$105	$105	$106	$106	$106	$107
ST capex	$ million	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capex on ST	$/kW-year	$26.48	$27.01	$27.55	$28.10	$28.66	$29.24	$29.82	$30.42	$31.03	$31.65	$32.28	$32.93	$33.59	$34.26	$34.94
Capacity of ST	kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC capex	$ million	$28	$28	$29	$29	$30	$31	$31	$32	$32	$33	$34	$34	$35	$36	$37
Capex on CC	$/kW-year	$36.55	$37.28	$38.02	$38.78	$39.56	$40.35	$41.16	$41.98	$42.82	$43.68	$44.55	$45.44	$46.35	$47.28	$48.22
Capacity of CC	kW	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000	757,000
GT capex	$ million	$27	$28	$28	$29	$27	$28	$28	$24	$24	$24	$25	$25	$24	$23	$23
Capex on GT	$/kW-year	$27.81	$28.37	$28.93	$29.51	$30.10	$30.70	$31.32	$31.94	$32.58	$33.24	$33.90	$34.58	$35.27	$35.97	$36.69
Capacity of GT	kW	984,000	984,000	984,000	984,000	902,000	902,000	902,000	736,000	736,000	736,000	736,000	736,000	686,000	636,000	636,000
Wind capex	$ million	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capex on Wind	$/kW-year	$25.81	$26.32	$26.85	$27.39	$27.94	$28.49	$29.06	$29.65	$30.24	$30.84	$31.46	$32.09	$32.73	$33.39	$34.05
Capacity of Wind	kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar capex	$ million	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capex on Solar	$/kW-year	$45.43	$46.34	$47.27	$48.21	$49.18	$50.16	$51.16	$52.19	$53.23	$54.30	$55.38	$56.49	$57.62	$58.77	$59.95
Capacity on Solar	kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydro capex	$ million	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Capex on Hydro	$/kW-year	$54.54	$55.63	$56.74	$57.87	$59.03	$60.21	$61.42	$62.64	$63.90	$65.18	$66.48	$67.81	$69.16	$70.55	$71.96
Capacity on Hydro	kW	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000	34,000
Total annual recurring capex for thermal		$ 55	$ 56	$ 57	$ 58	$ 57	$ 58	$ 59	$ 55	$ 56	$ 58	$ 59	$ 60	$ 59	$ 59	$ 60
Total annual recurring capex for renewables		$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2

Thermal capex amortization table	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
2018	$ million															
2019	$ million															
2020	$ million															
2021	$ million															
2022	$ million															
2023	$ million															
2024	$ million	$ 8														
2025	$ million	$ 9	$ 9													
2026	$ million	$ 9	$ 9	$ 9												
2027	$ million	$ 9	$ 9	$ 9	$ 9											
2028	$ million	$ 9	$ 9	$ 9	$ 9	$ 9										
2029	$ million	$ 9	$ 9	$ 9	$ 9	$ 9	$ 9									
2030	$ million	$ 9	$ 9	$ 9	$ 9	$ 9	$ 9	$ 9								
2031	$ million	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10							
2032	$ million	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10						
2033	$ million	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10					
2034	$ million		$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10				
2035	$ million			$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10			
2036	$ million				$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11		
2037	$ million					$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	
2038	$ million						$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11
2039	$ million							$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11	$ 11
2040	$ million								$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10
2041	$ million									$ 10	$ 10	$ 10	$ 10	$ 10	$ 10	$ 10
2042	$ million										$ 11	$ 11	$ 11	$ 11	$ 11	$ 11
2043	$ million											$ 11	$ 11	$ 11	$ 11	$ 11
2044	$ million												$ 11	$ 11	$ 11	$ 11
2045	$ million													$ 11	$ 11	$ 11
2046	$ million														$ 11	$ 11
2047	$ million															$ 11
Total	$ million	**$ 92**	**$ 94**	**$ 96**	**$ 98**	**$ 100**	**$ 101**	**$ 103**	**$ 103**	**$ 104**	**$ 105**	**$ 105**	**$ 106**	**$ 106**	**$ 106**	**$ 107**

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PREPA Rate Forecast Model - Cost - Labor and Operations (2) cont.

London Economics International LLC

Renewables capex amortization table		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
2018	$ million	$ 0	$ 0	$ 0	$ 0	$ 0										
2019	$ million	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0									
2020	$ million	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0								
2021	$ million	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0							
2022	$ million	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0						
2023	$ million	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0					
2024	$ million	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0				
2025	$ million	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0			
2026	$ million	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0		
2027	$ million	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	
2028	$ million	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2029	$ million	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2030	$ million	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2031	$ million	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2032	$ million	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2033	$ million	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2034	$ million		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2035	$ million			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2036	$ million				$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2037	$ million					$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2038	$ million						$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2039	$ million							$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2040	$ million								$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2041	$ million									$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2042	$ million										$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2043	$ million											$ 0	$ 0	$ 0	$ 0	$ 0
2044	$ million												$ 0	$ 0	$ 0	$ 0
2045	$ million													$ 0	$ 0	$ 0
2046	$ million														$ 0	$ 0
2047	$ million															$ 0
Total	$ million	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
O&M Generation	$ million	**$ 97**	**$ 98**	**$ 99**	**$ 100**	**$ 102**	**$ 103**	**$ 105**	**$ 92**	**$ 94**	**$ 96**	**$ 98**	**$ 100**	**$ 80**	**$ 60**	**$ 61**
Labor operating	$ million	$ 80	$ 81	$ 82	$ 83	$ 84	$ 85	$ 86	$ 88	$ 89	$ 91	$ 93	$ 94	$ 96	$ 98	$ 100
Non-labor/other operating	$ million	$ 83	$ 84	$ 85	$ 86	$ 87	$ 88	$ 90	$ 91	$ 92	$ 94	$ 96	$ 98	$ 100	$ 102	$ 104
Necessary maintenance	$ million	$ 89	$ 90	$ 91	$ 92	$ 94	$ 95	$ 96	$ 98	$ 99	$ 101	$ 103	$ 105	$ 108	$ 110	$ 112
Take out retired units	$ million	$ (155)	$ (157)	$ (159)	$ (160)	$ (163)	$ (165)	$ (167)	$ (184)	$ (187)	$ (191)	$ (194)	$ (198)	$ (224)	$ (250)	$ (255)
O&M T&D	$ million	**$ 1,037**	**$ 1,046**	**$ 1,056**	**$ 1,066**	**$ 1,078**	**$ 1,093**	**$ 1,108**	**$ 1,124**	**$ 1,183**	**$ 1,199**	**$ 1,218**	**$ 1,237**	**$ 1,257**	**$ 1,277**	**$ 1,300**
Labor operating - without concessionaire	$ million	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Non-labor/other operating - without concessionaire	$ million	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Necessary maintenance - without concessionaire	$ million	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Labor T&D with concessionaire	$ million	$ 387	$ 391	$ 395	$ 399	$ 405	$ 411	$ 417	$ 423	$ 430	$ 437	$ 445	$ 453	$ 461	$ 469	$ 478
Non-labor/other operating - with concessionaire	$ million	$ 408	$ 412	$ 417	$ 421	$ 427	$ 433	$ 440	$ 447	$ 453	$ 461	$ 469	$ 478	$ 486	$ 494	$ 504
Necessary maintenance - with concessionaire	$ million	$ 162	$ 164	$ 165	$ 167	$ 170	$ 172	$ 175	$ 177	$ 180	$ 183	$ 186	$ 190	$ 193	$ 196	$ 200
Bonus to concessionaire	$ million	$ 2	$ 2	$ 2	$ 2	$ 1	$ 1	$ 1	$ 1	$ 1	$ -	$ -	$ -	$ -	$ -	$ -
Concessionaire profit margin	$ million	$ 76	$ 76	$ 76	$ 77	$ 75	$ 75	$ 75	$ 75	$ 119	$ 117	$ 117	$ 117	$ 117	$ 117	$ 117
Concessionaire profit margin	$ million	$ 329	$ 354	$ 379	$ 370	$ 361	$ 352	$ 343	$ 334	$ 326	$ 318	$ 310	$ 302	$ 295	$ 287	$ 280
Concessionaire profit margin		$ 74	$ 74	$ 74	$ 74	$ 74	$ 74	$ 74	$ 74	$ 117	$ 117	$ 117	$ 117	$ 117	$ 117	$ 117
T&D asset base	$ million	$ 21,903	$ 23,623	$ 25,299	$ 24,666	$ 24,050	$ 23,448	$ 22,862	$ 22,291	$ 21,733	$ 21,190	$ 20,660	$ 20,144	$ 19,640	$ 19,149	$ 18,670
Concessionaire profit margin as																

trends for existing generation	%	1.00%	1.00%	1.00%	1.00%	1.50%	1.50%	1.50%	1.50%	1.50%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
trends for T&D	%	1.50%	1.50%	1.50%	1.50%	1.75%	1.75%	1.75%	1.75%	1.75%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
trends for existing generation factor	index	1.04	1.05	1.06	1.07	1.09	1.10	1.12	1.14	1.15	1.18	1.20	1.23	1.25	1.28	1.30
trends for T&D factor	index	1.16	1.18	1.20	1.21	1.24	1.26	1.28	1.30	1.32	1.35	1.38	1.40	1.43	1.46	1.49
X factor for Generation		*1.00%*	*1.00%*	*1.00%*	*1.00%*	*0.50%*	*0.50%*	*0.50%*	*0.50%*	*0.50%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*
X factor for T&D		*0.50%*	*0.50%*	*0.50%*	*0.50%*	*0.25%*	*0.25%*	*0.25%*	*0.25%*	*0.25%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*

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PREPA Rate Forecast Model - Cost - T&D capex

London Economics International LLC

		unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Cost of T&D capex	sum	$ million	$ -	$ -	$ 157	$ 167	$ 176	$ 186	$ 198	$ 85	$ 103	$ 122	$ 140	$ 159	$ 408	$ 656	$ 905
T&D rebuild and resilience spending	sum of the three items below	$ million	$ -	$ -	$ 121	$ 121	$ 121	$ 121	$ 121	$ 168	$ 168	$ 168	$ 168	$ 168	$ -	$ -	$ -
T&D rebuild and resilience spending	see cell B16	$ million	$ -	$ -	$ 121	$ 121	$ 121	$ 121	$ 121	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
-> which case is chosen in overview?	2	$ million															
gov. pay 58%	1	$ million	$ -	$ -	$ 508	$ 508	$ 508	$ 508	$ 508								
gov. pay 90%	2	$ million	$ -	$ -	$ 121	$ 121	$ 121	$ 121	$ 121								
Rebuild recommendation - T&D only	16.4 billion for 10 years, spead over 5 years, CFP2019 slide 118; see cell C28	$ million	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 168	$ 168	$ 168	$ 168	$ 168			
MATS compliance	CFP	$ million	$ -	$ -	$ 144	$ 140	$ 136	$ 133	$ 132	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MATS compliance	CFP2018, slide 38	$/kWh	$ -	$ -	$ 0	$ 0	$ 0	$ 0	$ 0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Load forecast in CFP Aug 2018	CFP2018, slide 36 top row	GWh	$ 11,910	$ 14,746	$ 14,391	$ 13,998	$ 13,635	$ 13,290	$ 13,150	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additional T&D for more renewables and grid modernization		$ million	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,267	$ 2,267	$ 2,267
Total T&D capex plan		$ million	$ -	$ -	$ 121	$ 121	$ 121	$ 121	$ 121	$ 168	$ 168	$ 168	$ 168	$ 168	$ 2,267	$ 2,267	$ 2,267
Grid invesmtment disbursed for the 16.4 billion		$ million	$ 1,950	$ 1,950	$ 3,016	$ 4,086	$ 5,160	$ 6,237	$ 7,315	$ 8,995	$ 10,675	$ 12,355	$ 14,035	$ 15,715	$ 15,715	$ 15,715	$ 15,715
Federal funding		$ million			$ 1,089	$ 1,089	$ 1,089	$ 1,089	$ 1,089	$ 1,512	$ 1,512	$ 1,512	$ 1,512	$ 1,512			
T&D Regulated Asset Base		$ million	$ 1,950	$ 1,950	$ 3,111	$ 4,243	$ 5,347	$ 6,424	$ 7,473	$ 8,966	$ 10,422	$ 11,842	$ 13,226	$ 14,575	$ 16,477	$ 18,332	$ 20,140
			2 billion already received from FEMA														

Investment budget			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
2018	-	$ million	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2019	-	$ million		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2020	121	$ million			$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13
2021	121	$ million				$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13
2022	121	$ million					$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13
2023	121	$ million						$13	$13	$13	$13	$13	$13	$13	$13	$13	$13
2024	121	$ million							$13	$13	$13	$13	$13	$13	$13	$13	$13
2025	168	$ million								$18	$18	$18	$18	$18	$18	$18	$18
2026	168	$ million									$18	$18	$18	$18	$18	$18	$18
2027	168	$ million										$18	$18	$18	$18	$18	$18
2028	168	$ million											$18	$18	$18	$18	$18
2029	168	$ million												$18	$18	$18	$18
2030	2,267	$ million													$249	$249	$249
2031	2,267	$ million														$249	$249
2032	2,267	$ million															$249
2033	2,267	$ million															
2034	2,267	$ million															
2035	2,267	$ million															
2036	-	$ million															
2037	-	$ million															
2038	-	$ million															
2039	-	$ million															
2040	-	$ million															
2041	-	$ million															
2042	-	$ million															
2043	-	$ million															
2044	-	$ million															
2045	-	$ million															
2046	-	$ million															
2047	-	$ million															
Total		$ million	$ -	$ -	$ 13	$ 27	$ 40	$ 53	$ 66	$ 85	$ 103	$ 122	$ 140	$ 159	$ 408	$ 656	$ 905

How much to spend in first 5 years $ million 8000

PMT calculation

Rebuild and resilience spending, excluding gov	assuming 58% from gov.	assuming 90% from gov.
Interest rate	11%	11%
Years	40	40
T&D rebuild and resilience spending, excluding gov (million)	2541	605
PMT per year, million	279.015	66.432

Rebuild recommendation 16.4 billion-8 billion	
Interest rate	11%
Years	40
Rebuild recommendation 16.4 billion-8 billion (million)	8400
PMT per year, million	922

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PREPA Rate Forecast Model - Cost - T&D capex cont.

London Economics International LLC

	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Total Cost of T&D capex	$ million	$ 1,154	$ 1,403	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652			
T&D rebuild and resilience spending	$ million	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
T&D rebuild and resilience spending	$ million	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
Rebuild recommendation - T&D only	$ million																		
MATS compliance	$ million	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
MATS compliance	$/kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
Load forecast in CFP Aug 2018	GWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
Additional T&D for more renewables and grid modernization	$ million	$ 2,267	$ 2,267	$ 2,267	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
Total T&D capex plan	$ million	$ 2,267	$ 2,267	$ 2,267	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
Grid invesmtment disbursed for the 16.4 billion	$ million	$ 15,715	$ 15,715	$ 15,715	$ 15,715	$ 15,715	$ 15,715	$ 15,715	$ 15,715	$ 15,715	$ 15,715	$ 15,715	$ 15,715	$ 15,715	$ 15,715	$ 15,715	15,715	15,715	15,715
Federal funding	$ million																		
T&D Regulated Asset Base	$ million	$ 21,903	$ 23,623	$ 25,299	$ 24,666	$ 24,050	$ 23,448	$ 22,862	$ 22,291	$ 21,733	$ 21,190	$ 20,660	$ 20,144	$ 19,640	$ 19,149	$ 18,670	$ 18,204	$ 17,749	$ 17,305

		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
2018	$ million	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2019	$ million	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2020	$ million	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13
2021	$ million	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13
2022	$ million	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13
2023	$ million	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13
2024	$ million	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13	$13
2025	$ million	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18
2026	$ million	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18
2027	$ million	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18
2028	$ million	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18
2029	$ million	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18	$18
2030	$ million	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249
2031	$ million	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249
2032	$ million	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249
2033	$ million	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249
2034	$ million		$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249
2035	$ million			$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249	$249
2036	$ million				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2037	$ million					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2038	$ million						$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2039	$ million							$0	$0	$0	$0	$0	$0	$0	$0	$0
2040	$ million								$0	$0	$0	$0	$0	$0	$0	$0
2041	$ million									$0	$0	$0	$0	$0	$0	$0
2042	$ million										$0	$0	$0	$0	$0	$0
2043	$ million											$0	$0	$0	$0	$0
2044	$ million												$0	$0	$0	$0
2045	$ million													$0	$0	$0
2046	$ million														$0	$0
2047	$ million															$0.00
Total	$ million	$ 1,154	$ 1,403	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652	$ 1,652

Confidential

PREPA Rate Forecast Model - Cost - CILT and subsidies

London Economics International LLC

	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total CILT	$ million	$ 277.9	$ 277.9	$ 274.3	$ 270.8	$ 267.6	$ 264.5	$ 261.5	$ 258.7	$ 256.0	$ 253.5	$ 251.1	$ 248.8	$ 246.6	$ 244.6	$ 242.6
CILT and other appropriations	$ million	$ 257.9	$ 257.9	$ 254.3	$ 250.8	$ 247.6	$ 244.5	$ 241.5	$ 238.7	$ 236.0	$ 233.5	$ 231.1	$ 228.8	$ 226.6	$ 224.6	$ 222.6
CILT	$ million	$ 72.5	$ 72.5	$ 68.9	$ 65.4	$ 62.1	$ 59.0	$ 56.1	$ 53.3	$ 50.6	$ 48.1	$ 45.7	$ 43.4	$ 41.2	$ 39.2	$ 37.2
Consumption cap	GWh	*363*	363	345	328	311	296	281	267	253	241	229	217	206	196	186
Other appropriations	$ million	$ 185	$ 185	$ 185	$ 185	$ 185	$ 185	$ 185	$ 185	$ 185	$ 185	$ 185	$ 185	$ 185	$ 185	$ 185
Regulator's budget	$ million	*20*	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20

Assumption for CILT rate		Budget June 2	Implied rates
CILT historical numbers	$ million	72.47	0.19971177 $/kWh
Other	$ million	*185*	N/A

CFP2019 figure for benchmarking		2018	2019	2020	2021	2022	2023
CILT and subsidies	$ million	*$ 212*	*$ 297*	*$ 282*	*$ 271*	*$ 259*	*$ 254*

Confidential

PREPA Rate Forecast Model - Cost - CILT and subsidies cont.

London Economics International LLC

	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total CILT	$ million	**$ 240.8**	**$ 239.0**	**$ 237.3**	**$ 235.7**	**$ 234.2**	**$ 232.8**	**$ 231.4**	**$ 230.1**	**$ 228.9**	**$ 227.7**	**$ 226.6**	**$ 225.5**	**$ 224.5**	**$ 223.6**	**$ 222.7**
CILT and other appropriations	$ million	$ 220.8	$ 219.0	$ 217.3	$ 215.7	$ 214.2	$ 212.8	$ 211.4	$ 210.1	$ 208.9	$ 207.7	$ 206.6	$ 205.5	$ 204.5	$ 203.6	$ 202.7
CILT	$ million	$ 35.3	$ 33.6	$ 31.9	$ 30.3	$ 28.8	$ 27.3	$ 26.0	$ 24.7	$ 23.4	$ 22.3	$ 21.2	$ 20.1	$ 19.1	$ 18.1	$ 17.2
Consumption cap	GWh	177	168	160	152	144	137	130	124	117	112	106	101	96	91	86
Other appropriations	$ million	$ 185	$ 185	$ 185	$ 185	$ 185	$ 185	$ 185	$ 185	$ 185	$ 185	$ 185	$ 185	$ 185	$ 185	$ 185
Regulator's budget	$ million	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20

Confidential

PREPA Rate Forecast Model - Cost - Fuel and purchased power

London Economics International LLC

	calculation	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Fuel and Purchased Power			$ 1,425	$ 2,219	$ 2,319	$ 2,135	$ 1,585	$ 1,601	$ 1,540	$ 1,389	$ 1,423	$ 1,428	$ 1,479	$ 1,660	$ 1,644	$ 1,611	$ 1,571
Fuel cost			$ 836	$ 1,553	$ 1,362	$ 1,435	$ 942	$ 912	$ 849	$ 698	$ 689	$ 675	$ 798	$ 771	$ 738	$ 699	$ 658
PPA for existing thermal			$ 534	$ 610	$ 671	$ 386	$ 378	$ 374	$ 372	$ 378	$ 386	$ 393	$ 280	$ 285	$ 291	$ 298	$ 305
PPA for existing renewables			$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56
New PPA for renewables			$ -	$ -	$ -	$ 14	$ 50	$ 63	$ 78	$ 97	$ 111	$ 124	$ 135	$ 142	$ 148	$ 151	$ 152
PPA for generic new non-renewables			$ -	$ -	$ -	$ -	$ -	$ 41	$ 41	$ 41	$ 65	$ 65	$ 75	$ 276	$ 286	$ 289	$ 289
CFP forecasted inefficiency dispatch cost		c/kWh			*1.26*	*1.28*	*1.12*	*1.13*	*1.08*								
Source	CFP 2019 slide 66 and 69																
Implied total inefficient cost		$ million			$ 193	$ 184	$ 145	$ 141	$ 135								
CFP forecasted non-renewable fuel cost		$ million			*1,140*	*740*	*601*	*442*	*398*								
Source	CFP 2019 slide 66 and 69																
Implied inefficiency dispatch cost as % of fuel cost		%			16.9%	24.8%	24.2%	31.8%	34.0%								
Implied Inefficiency dispatch		$ million		$ 193	$ 230	$ 243	$ 159	$ 154	$ 144	$ 118	$ 117	$ 114	$ 135	$ 130	$ 125	$ 118	$ 111
		unit	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Fuel costs for existing assets		$ million	$ 836	$ 1,378	$ 1,176	$ 905	$ 404	$ 366	$ 295	$ 0	$ -	$ -	$ -	$ -	$ -	$ -	$ 0
Oil fuel cost total		$ million	$ 537	$ 319	$ 114	$ 118	$ 122	$ 108	$ 112	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fuel prices $/MMBtu		$/MMBtu	$ 13	$ 13	$ 13	$ 14	$ 14	$ 14	$ 15	$ 15	$ 16	$ 16	$ 17	$ 18	$ 18	$ 19	$ 19
Annual production convert to MMBtu		MMBtu	41,476,322	24,794,409	8,728,250	8,728,250	8,728,250	7,480,226	7,480,226	-	-	-	-	-	-	-	-
Diesel fuel cost total		$ million	$ -	$ 783	$ 1,062	$ 786	$ 282	$ 258	$ 184	$ 0	$ -	$ -	$ -	$ -	$ -	$ -	$ 0
Fuel prices $/MMBtu		$/MMBtu	$ 16	$ 16	$ 17	$ 18	$ 18	$ 19	$ 19	$ 20	$ 20	$ 21	$ 21	$ 22	$ 22	$ 23	$ 24
Annual production convert to MMBtu		MMBtu	-	49,500,192	61,043,857	44,067,439	15,421,157	13,745,290	9,537,326	0	-	-	-	-	-	-	0
Natural gas fuel cost total		$ million	$ 298	$ 276	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fuel prices $/MMBtu		$/MMBtu	$ 8	$ 7	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 9	$ 9	$ 9	$ 9	$ 9	$ 10	$ 10
Annual production convert to MMBtu		MMBtu	37,427,527	37,427,527	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel costs for converted assets and planned new CCGT		$ million	$ -	$ 176	$ 185	$ 188	$ 192	$ 195	$ 199	$ 432	$ 424	$ 412	$ 589	$ 568	$ 544	$ 516	$ 485
Natural gas fuel cost total		$ million	$ -	$ 176	$ 185	$ 188	$ 192	$ 195	$ 199	$ 432	$ 424	$ 412	$ 589	$ 568	$ 544	$ 516	$ 485
Fuel prices $/MMBtu		$/MMBtu	$ 8	$ 7	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 9	$ 9	$ 9	$ 9	$ 9	$ 10	$ 10
Annual production convert to MMBtu		MMBtu	-	23,863,361	23,863,361	23,863,361	23,863,361	23,863,361	23,863,361	50,880,524	49,015,258	46,722,070	65,499,850	61,979,594	58,142,085	54,005,587	49,754,416
Purchased Power for existing assets		**unit**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Total		$ million	*$ 534*	*$ 610*	*$ 671*	$ 386	$ 378	$ 374	$ 372	$ 378	$ 386	$ 393	$ 280	$ 285	$ 291	$ 298	$ 305
Fuel cost for AES Coal		$ million				$ 111	$ 110	$ 111	$ 111	$ 113	$ 115	$ 117	$ -	$ -	$ -	$ -	$ -
Annual generation MWh		MWh	-	3,460,025	3,460,025	3,460,025	3,460,025	3,460,025	3,460,025	3,460,025	3,460,025	3,460,025	-	-	-	-	-
Fuel cost for Ecoelectrica		$ million				$ 232	$ 236	$ 240	$ 244	$ 154	$ 151	$ 147	$ 210	$ 202	$ 194	$ 184	$ 173
Annual generation MWh		MWh	2,999,834	2,999,834	3,908,362	3,908,362	3,908,362	3,908,362	3,908,362	2,414,627	2,326,107	2,217,280	3,108,413	2,941,353	2,759,237	2,562,932	2,361,185
PPA for existing renewables		$ million	*$ 56*	*$ 56*	*$ 56*	*$ 56*	*$ 56*	*$ 56*	*$ 56*	*$ 56*	*$ 56*	*$ 56*	*$ 56*	*$ 56*	*$ 56*	*$ 56*	*$ 56*
Source	CFP 2019 slide 38																
		unit	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
New wind		$ million	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Nameplate capacity MW		MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Load factor %		%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Annual generation MWh		MWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LCOE $/MWh or $kW-year		$/MWh	$ 111	$ 112	$ 112	$ 114	$ 115	$ 116	$ 118	$ 161	$ 163	$ 165	$ 167	$ 169	$ 172	$ 174	$ 176
New solar		$ million	$ -	$ -	$ -	$ 14	$ 50	$ 63	$ 78	$ 97	$ 111	$ 124	$ 135	$ 142	$ 148	$ 151	$ 152
Nameplate capacity MW		MW	-	-	-	200	711	897	1,124	1,325	1,465	1,611	1,726	1,810	1,874	1,904	1,916
Load factor %		%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%
Annual generation MWh		MWh	-	-	-	385,440	1,369,859	1,727,930	2,165,378	2,554,343	2,823,170	3,104,272	3,326,307	3,488,882	3,611,878	3,668,472	3,692,069
LCOE $/MWh or $kW-year		$/MWh	$ 73	$ 71	$ 71	$ 70	$ 70	$ 69	$ 69	$ 95	$ 94	$ 93	$ 92	$ 91	$ 90	$ 91	$ 91
New batteries - Reserve Margins		$ million	$ -	$ -	$ -	$ -	$ -	$ 31	$ 31	$ 31	$ 48	$ 48	$ 55	$ 198	$ 205	$ 208	$ 208
Cumulative nameplate capacity MW		MW	-	-	-	-	-	73	73	73	116	116	135	511	529	536	536
LCOE $/MWh or $kW-year		$/kW-year	$ 463	$ 452	$ 443	$ 435	$ 428	$ 421	$ 414	$ 407	$ 400	$ 394	$ 387	$ 381	$ 374	$ 368	$ 361
New CCGTs		$ million	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cumulative nameplate capacity MW		MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Load factor %		%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
Annual generation MWh		MWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LCOE $/MWh or $kW-year		$/MWh	$ 80	$ 76	$ 78	$ 79	$ 80	$ 82	$ 83	$ 84	$ 85	$ 86	$ 87	$ 89	$ 90	$ 92	$ 93
New Peaker		$ million	$ -	$ -	$ -	$ -	$ -	$ 10	$ 10	$ 10	$ 17	$ 17	$ 20	$ 77	$ 80	$ 81	$ 81
Cumulative nameplate capacity MW		MW	-	-	-	-	-	31	31	31	50	50	58	219	227	230	230
LCOE $/MWh or $kW-year		$/kW-year	$ 317	$ 319	$ 322	$ 325	$ 329	$ 333	$ 338	$ 342	$ 346	$ 350	$ 354	$ 358	$ 363	$ 367	$ 372

Confidential

PREPA Rate Forecast Model - Cost - Fuel and purchased power (2)

London Economics International LLC

		unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Oil prices $/MMBtu	EIA	$/MMBtu	$ 13	$ 13	$ 13	$ 14	$ 14	$ 14	$ 15	$ 15	$ 16	$ 16	$ 17	$ 18	$ 18	$ 19	$ 19
Diesel prices $/MMBtu	EIA	$/MMBtu	$ 16	$ 16	$ 17	$ 18	$ 18	$ 19	$ 19	$ 20	$ 20	$ 21	$ 21	$ 22	$ 22	$ 23	$ 24
LNG prices $/MMBtu	Henry hub * 1.15 + 4.35	$/MMBtu	$ 8	$ 7	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 9	$ 9	$ 9	$ 9	$ 9	$ 10	$ 10
Assumed coal price generation cost	IRP 2019 page 193	$/tonne	$ 79	$ 72	$ 69	$ 69	$ 68	$ 68	$ 68	$ 69	$ 70	$ 71	$ 72	$ 73	$ 74	$ 75	$ 77
Conversion factor (tonne/MMBtu)		tonne/MMBtu	27.8														
Assumed coal price generation cost		$/MMBtu	$ 3	$ 3	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3

Purchased Power for existing assets

AES Coal									
454 MW									
2505636 MWh									
	2019	2020	2021	2022	2023	2024	2025	2026	2027
Fixed O&M $/kW	$ 80	$ 82	$ 84	$ 86	$ 88	$ 90	$ 92	$ 94	$ 97
Variable O&M $/MWh	$ 7	$ 7	$ 8	$ 8	$ 8	$ 8	$ 8	$ 9	$ 9
Capital Costs $	$ 122,916,000	$ 122,991,000	##########	##########	##########	##########	##########	##########	##########
Total costs $ million			$ 165	$ 152	$ 144	$ 135	$ 138	$ 140	$ 142
Fixed costs	$ 159	$ 160	$ 146	$ 133	$ 124	$ 115	$ 117	$ 118	$ 120
Heat rate (MMBtu/MWh)	9.79	9.79	9.79	9.79	9.79	9.79	9.79	9.79	9.79
Generation cost $/MWh	$ 33	$ 32	$ 32	$ 32	$ 32	$ 32	$ 33	$ 33	$ 34
Source	IRP 2019 page 95								

EcoElectrica	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Heat rate (MMBtu/MWh)	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Variable O&M $/MWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Generation cost $/MWh	$ 59.2	$ 60.3	$ 61.4	$ 62.5	$ 63.6	$ 64.8	$ 66.1	$ 67.4	$ 68.8	$ 70.2	$ 71.6	$ 73.2	$ 74.7	$ 76.4	$ 78.1	$ 79.9	$ 81.7
Total Fixed costs $ million	$ 240.1	$ 245.3	$ 250.7	$ 256.8	$ 261.6	$ 267.3	$ 273.1	$ 279.7	$ 285.1	$ 291.3	$ 297.5	$ 304.8	$ 310.6	$ 317.3	$ 324.2	$ 332.2	$ 338.5

PREPA Rate Forecast Model - Cost - Fuel and purchased power cont.

London Economics International LLC

	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total Fuel and Purchased Power		$ 1,530	$ 1,490	$ 1,454	$ 1,419	$ 1,381	$ 1,345	$ 1,324	$ 1,308	$ 1,294	$ 1,281	$ 1,265	$ 1,248	$ 1,232	$ 1,214	$ 1,196
Fuel cost		$ 618	$ 578	$ 541	$ 504	$ 466	$ 435	$ 417	$ 404	$ 392	$ 380	$ 366	$ 353	$ 338	$ 323	$ 308
PPA for existing thermal		$ 311	$ 317	$ 324	$ 332	$ 338	$ 338	$ 338	$ 338	$ 338	$ 338	$ 338	$ 338	$ 338	$ 338	$ 338
PPA for existing renewables		$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56
New PPA for renewables		$ 153	$ 153	$ 153	$ 153	$ 153	$ 153	$ 153	$ 153	$ 153	$ 153	$ 153	$ 153	$ 153	$ 153	$ 153
PPA for generic new non-renewables		$ 289	$ 289	$ 289	$ 289	$ 289	$ 289	$ 289	$ 289	$ 289	$ 289	$ 289	$ 289	$ 289	$ 289	$ 289
CFP forecasted inefficiency dispatch cost	c/kWh															
Implied total inefficient cost	$ million															
CFP forecasted non-renewable fuel cost	$ million															
Implied inefficiency dispatch cost as % of fu	%															
Implied Inefficiency dispatch	$ million	$ 105	$ 98	$ 92	$ 85	$ 79	$ 74	$ 71	$ 68	$ 66	$ 64	$ 62	$ 60	$ 57	$ 55	$ 52

	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Fuel costs for existing assets	$ million	$ 0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ -
Oil fuel cost total	$ million	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fuel prices $/MMBtu	$/MMBtu	$ 20	$ 21	$ 21	$ 22	$ 23	$ 24	$ 24	$ 25	$ 26	$ 27	$ 28	$ 29	$ 30	$ 31	$ 32
Annual production convert to MMB	MMBtu	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Diesel fuel cost total	$ million	$ 0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ -
Fuel prices $/MMBtu	$/MMBtu	$ 24	$ 25	$ 25	$ 26	$ 27	$ 27	$ 28	$ 29	$ 30	$ 30	$ 31	$ 32	$ 33	$ 34	$ 35
Annual production convert to MMB	MMBtu	0	-	-	-	-	-	-	-	-	0	-	-	-	-	-
Natural gas fuel cost total	$ million	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fuel prices $/MMBtu	$/MMBtu	$ 10	$ 10	$ 10	$ 11	$ 11	$ 11	$ 11	$ 12	$ 12	$ 12	$ 13	$ 13	$ 13	$ 14	$ 14
Annual production convert to MMB	MMBtu	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel costs for converted assets and planned	$ million	$ 456	$ 426	$ 399	$ 372	$ 343	$ 321	$ 308	$ 298	$ 289	$ 280	$ 270	$ 260	$ 249	$ 238	$ 227
Natural gas fuel cost total	$ million	$ 456	$ 426	$ 399	$ 372	$ 343	$ 321	$ 308	$ 298	$ 289	$ 280	$ 270	$ 260	$ 249	$ 238	$ 227
Fuel prices $/MMBtu	$/MMBtu	$ 10	$ 10	$ 10	$ 11	$ 11	$ 11	$ 11	$ 12	$ 12	$ 12	$ 13	$ 13	$ 13	$ 14	$ 14
Annual production convert to MMB	MMBtu	45,714,775	41,833,744	38,318,665	34,910,161	31,530,415	28,786,085	26,945,110	25,480,751	24,130,034	22,852,971	21,479,106	20,153,604	18,845,683	17,536,826	16,275,804

Purchased Power for existing assets	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total	$ million	$ 311	$ 317	$ 324	$ 332	$ 338	$ 338	$ 338	$ 338	$ 338	$ 338	$ 338	$ 338	$ 338	$ 338	$ 338
Fuel cost for AES Coal	$ million	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Annual generation MWh	MWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fuel cost for Ecoelectrica	$ million	$ 162	$ 152	$ 142	$ 132	$ 122	$ 114	$ 109	$ 106	$ 103	$ 100	$ 96	$ 93	$ 89	$ 85	$ 81
Annual generation MWh	MWh	2,169,477	1,985,296	1,818,481	1,656,725	1,496,333	1,366,096	1,278,729	1,209,235	1,145,134	1,084,529	1,019,330	956,426	894,356	832,242	772,398
PPA for existing renewables	$ million	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56	$ 56

	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
New wind	$ million	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Nameplate capacity MW	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Load factor %	%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Annual generation MWh	MWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LCOE $/MWh or $kW-year	$/MWh	$ 179	$ 182	$ 185	$ 188	$ 191	$ 194	$ 198	$ 202	$ 207	$ 211	$ 215	$ 220	$ 224	$ 229	$ 234
New solar	$ million	$ 153	$ 153	$ 153	$ 153	$ 153	$ 153	$ 153	$ 153	$ 153	$ 153	$ 153	$ 153	$ 153	$ 153	$ 153
Nameplate capacity MW	MW	1,921	1,921	1,921	1,921	1,921	1,921	1,921	1,921	1,921	1,921	1,921	1,921	1,921	1,921	1,921
Load factor %	%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%
Annual generation MWh	MWh	3,703,041	3,703,041	3,703,041	3,703,041	3,703,041	3,703,041	3,703,041	3,703,041	3,703,041	3,703,041	3,703,041	3,703,041	3,703,041	3,703,041	3,703,041
LCOE $/MWh or $kW-year	$/MWh	$ 91	$ 91	$ 92	$ 92	$ 93	$ 93	$ 94	$ 94	$ 95	$ 96	$ 97	$ 98	$ 98	$ 99	$ 100
New batteries - Reserve Margins	$ million	$ 208	$ 208	$ 208	$ 208	$ 208	$ 208	$ 208	$ 208	$ 208	$ 208	$ 208	$ 208	$ 208	$ 208	$ 208
Cumulative nameplate capacity MW	MW	536	536	536	536	536	536	536	536	536	536	536	536	536	536	536
LCOE $/MWh or $kW-year	$/kW-year	$ 355	$ 350	$ 344	$ 339	$ 334	$ 329	$ 325	$ 322	$ 318	$ 315	$ 311	$ 308	$ 305	$ 301	$ 298
New CCGTs	$ million	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cumulative nameplate capacity MW	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Load factor %	%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
Annual generation MWh	MWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LCOE $/MWh or $kW-year	$/MWh	$ 95	$ 97	$ 98	$ 100	$ 102	$ 104	$ 107	$ 109	$ 111	$ 114	$ 116	$ 119	$ 122	$ 124	$ 127
New Peaker	$ million	$ 81	$ 81	$ 81	$ 81	$ 81	$ 81	$ 81	$ 81	$ 81	$ 81	$ 81	$ 81	$ 81	$ 81	$ 81
Cumulative nameplate capacity MW	MW	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230
LCOE $/MWh or $kW-year	$/kW-year	$ 376	$ 382	$ 387	$ 393	$ 399	$ 404	$ 412	$ 419	$ 427	$ 435	$ 443	$ 451	$ 460	$ 468	$ 477

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PREPA Rate Forecast Model - Cost - Fuel and purchased power (2) cont.

London Economics International LLC

	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
																289
Oil prices $/MMBtu	$/MMBtu	$ 20	$ 21	$ 21	$ 22	$ 23	$ 24	$ 24	$ 25	$ 26	$ 27	$ 28	$ 29	$ 30	$ 31	$ 32
Diesel prices $/MMBtu	$/MMBtu	$ 24	$ 25	$ 25	$ 26	$ 27	$ 27	$ 28	$ 29	$ 30	$ 30	$ 31	$ 32	$ 33	$ 34	$ 35
LNG prices $/MMBtu	$/MMBtu	$ 10	$ 10	$ 10	$ 11	$ 11	$ 11	$ 11	$ 12	$ 12	$ 12	$ 13	$ 13	$ 13	$ 14	$ 14
Assumed coal price generation cost	$/tonne	$ 78	$ 79	$ 81	$ 82	$ 83	$ 85	$ 86	$ 88							
Conversion factor (tonne/MMBtu)	tonne/MMBtu															
Assumed coal price generation cost	$/MMBtu	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3							

EcoElectrica	2022	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Heat rate (MMBtu/MWh)	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Variable O&M $/MWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Generation cost $/MWh	$ 81.7	$ 83.6	$ 85.6	$ 87.7	$ 89.8	$ 92.1	$ 94.4	$ 96.8	$ 99.3	$ 101.9	$ 104.6
Total Fixed costs $ million	$ 245.3	$ 338.5	$ 338.5	$ 338.5	$ 338.5	$ 338.5	$ 338.5	$ 338.5	$ 338.5	$ 338.5	$ 338.5

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PREPA Rate Forecast Model - Generation Plan

London Economics International LLC

ICAP	calculation	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total	Existing+New	MW	5240	4380	3760	4303	4583	4483	5379	5518	5920	6060	5606	5606	5606	5606	5606
Step 1 - existing capacity by tech by fuel																	
Existing Total		MW	5,240	4,340	3,520	3,045	3,045	2,945	2,945	2,253	2,253	2,253	1,799	1,799	1,799	1,799	1,799
ST		MW	2,352	1,452	632	532	532	432	432	-	-	-	-	-	-	-	-
Gas		MW	820	820	-	-	-	-	-	-	-	-	-	-	-	-	-
Fuel oil #6		MW	1,532	632	632	532	532	432	432	-	-	-	-	-	-	-	-
CC (Diesel)		MW	920	920	920	920	920	920	920	660	660	660	660	660	660	660	660
GT (Diesel)		MW	744	744	744	366	366	366	366	366	366	366	366	366	366	366	366
Hydro		MW	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
IPP		MW	1,190	1,190	1,190	1,193	1,193	1,193	1,193	1,193	1,193	1,193	739	739	739	739	739
AES Coal		MW	454	454	454	454	454	454	454	454	454	454	-	-	-	-	-
EcoElectrica (CCGT)		MW	507	507	507	507	507	507	507	507	507	507	507	507	507	507	507
Solar	IRP 2019	MW	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126
Wind		MW	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101
Landfill Gas	pre-operation in 2021	MW	2	2	2	5	5	5	5	5	5	5	5	5	5	5	5
Step 2 - add additional new entry / retirement based on the ESM plan in IRP 2019																	
New additions in the ESM plan		MW	0	40	240	1258	1538	1538	1538	2142	2342	2342	2342	2342	2342	2342	2342
CCGT (Natural Gas)		MW	0	-	-	-	-	-	-	604	604	604	604	604	604	604	604
Peakers diesel & gas		MW	0	-	-	418	618	618	618	618	618	618	618	618	618	618	618
Solar		MW	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind		MW	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BESS		MW	0	40	240	840	920	920	920	920	1120	1120	1120	1120	1120	1120	1120
CC Diesel convert to Gas	deduct diesel	MW	0	(400)	(400)	(400)	(400)	(400)	(400)	(600)	(600)	(600)	(600)	(600)	(600)	(600)	(600)
CC Diesel convert to Gas	add gas	MW	0	400	400	400	400	400	400	600	600	600	600	600	600	600	600
Additional retirement of Diesel CC & large GTs		MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Step 3 - add more renewable to meet RPS goals																	
LEI modeled additional renewable to meet RPS		MW	0	0	0	0	0	0	897	1,124	1,325	1,465	1,465	1,465	1,465	1,465	1,465
Accumulative RPS solar		MW		0	-	-	200	711	897	1,124	1,325	1,465	1,611	1,726	1,810	1,874	1,904
Accumulative RPS wind		MW		0	0	0	0	0	0	0	0	0	0	0	0	0	0
Additional solar for that year only	more solar	MW		-	-	200	511	186	227	202	139	146	115	84	64	29	12
Additional wind for that year only		MW		-	-	-	-	-	-	-	-	-	-	-	-	-	-
RPS Automatic buildup logic																	
RPS target milestones	FP2018, slide 44; RPS goals	%	6%	6%	6%	0%	0%	0%	0%	20%	0%	0%	0%	0%	0%	0%	0%
Previous milestone value		%	6%	6%	6%	6%	6%	6%	6%	20%	20%	20%	20%	20%	20%	20%	20%
Previous milestone year		year	2018	2019	2020	2020	2020	2020	2020	2025	2025	2025	2025	2025	2025	2025	2025
Next milestone value		%	6%	6%	20%	20%	20%	20%	20%	40%	40%	40%	40%	40%	40%	40%	40%
Next milestone year		year	2018	2018	2025	2025	2025	2025	2025	2035	2035	2035	2035	2035	2035	2035	2035
Smoothed target		%	6%	6%	6%	9%	12%	14%	17%	20%	22%	24%	26%	28%	30%	32%	34%
Total generation		MWh	-	19,052,023	18,331,220	17,299,517	15,809,280	15,221,853	15,287,181	15,091,803	14,941,758	14,867,871	14,578,169	14,117,499	13,586,319	12,914,030	12,223,783
Total renewables required		MWh		1,143,121	1,099,873	1,522,358	1,833,877	2,191,947	2,629,395	3,018,361	3,287,187	3,568,289	3,790,324	3,952,900	4,075,896	4,132,490	4,156,086
Ratio of new wind and solar																	
Solar		%		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Wind		%		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Existing solar generation		MWh		242,827	242,827	242,827	242,827	242,827	242,827	242,827	242,827	242,827	242,827	242,827	242,827	242,827	242,827
Existing wind generation		MWh		221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190
Incremental new renewable generation required		MWh			-	1,058,340	984,419	358,070	437,448	388,966	268,826	281,102	222,035	162,576	122,996	56,594	23,597
Solar generation required	assumed same solar/wind ratio in	MWh		-	-	1,058,340	984,419	358,070	437,448	388,966	268,826	281,102	222,035	162,576	122,996	56,594	23,597
Wind generation required	assumed same solar/wind ratio in	MWh		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing solar installed capacity	IRP 2019 page 81 show what is	MW		-	-	549	511	186	227	202	139	146	115	84	64	29	12
Existing wind installed capacity	IRP 2019 page 81	MW		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar capacity factor	22%	%															
Wind capacity factor	25%	%															

Confidential

PREPA Rate Forecast Model - Generation Plan (2)

London Economics International LLC

Step 4 - add more capacity to meet Reserve Margin			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Additional MW needed to meet Reserve Margin	negative means no need to add	MW	**1,161**	**2,502**	**2,469**	**1,162**	**104**	**(440)**	**(225)**	**62**	**(84)**	**27**	**537**	**27**	**9**	**(13)**	**(40)**
Additional Batteries	70%	MW					73	-	-	43	-	19	376	19	7	-	-
Additional Gas peakers	30%	MW					31	-	-	18	-	8	161	8	3	-	-
Total capacity needed	calculated by RM and peak load	MW	5,892	6,373	5,720	4,953	4,175	3,635	3,850	4,049	4,165	4,276	4,358	4,385	4,395	4,382	4,355
Cumulative batteries added		MW	-	-	-	-	-	73	73	73	116	116	135	511	529	536	536
Cumulative gas peakers added		MW	-	-	-	-	-	31	31	31	50	50	58	219	227	230	230
Reserve margin (nameplate capacity)	Start at CFP 2018 Slide 45, forecasted based on Hawaii's RM to achieve % of renewable	%	*130%*	114%	98%	82%	66%	50%	59%	69%	76%	83%	90%	97%	103%	110%	117%
Renewable target in PR		%	*6%*					14%	17%	20%	22%	24%	26%	28%	30%	32%	34%
Reserve margin in Hawaii	Hawaii PSIP Plan	%	*72%*	*73%*	*103%*	*110%*	*114%*	*115%*	*120%*	*125%*	*131%*	*137%*	*145%*	*152%*	*157%*	*158%*	*157%*
- Source	https //puc.hawaii.gov/wp-content/uploads/2019/02/AOS2019-HECO.pdf																
Renewable target in Hawaii		%			30%										40%		
Peak load	Calculated	MW	2562	2979	2891	2725	2520	2429	2417	2397	2369	2340	2299	2232	2161	2084	2005
Peak load CAGR		%	-2.14%														

Simplified supply stack

		unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Demand		MWh		19,052,023	18,331,220	17,299,517	15,809,280	15,221,853	15,287,181	15,091,803	14,941,758	14,867,871	14,578,169	14,117,499	13,586,319	12,914,030	12,223,783
Wind capacity		MW		101	101	101	101	101	101	101	101	101	101	101	101	101	101
Wind generation		MWh	-	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190
Solar capacity		MW		126	126	526	1,348	1,208	1,477	1,653	1,730	1,883	1,967	2,021	2,064	2,059	2,054
Solar generation		MWh	-	242,827	242,827	1,013,707	2,597,106	2,328,827	2,845,653	3,186,136	3,334,823	3,628,201	3,791,169	3,894,285	3,977,702	3,967,893	3,958,493
Hydro capacity		MWh		34	34	34	34	34	34	34	34	34	34	34	34	34	34
Hydro generation		MWh	37,838	37,838	37,838	37,838	37,838	37,838	37,838	37,838	37,838	37,838	37,838	37,838	37,838	37,838	37,838
Landfill gas capacity		MW		2	2	5	5	5	5	5	5	5	5	5	5	5	5
Landfill gas generation		MWh		18,922	18,922	37,843	37,843	37,843	37,843	37,843	37,843	37,843	37,843	37,843	37,843	37,843	37,843
Remaining for non-renewable units		MWh		18,531,246	17,810,443	15,988,939	12,915,303	12,596,154	12,144,656	11,608,796	11,310,064	10,942,798	10,490,129	9,926,342	9,311,746	8,649,265	7,968,419
Coal capacity		MW		454	454	454	454	454	454	454	454	454	-	-	-	-	-
Assumed coal maximum capacity factor	87%																
Implied capacity factor for coal		%		87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%
Coal generation		MWh		3,460,025	3,460,025	3,460,025	3,460,025	3,460,025	3,460,025	3,460,025	3,460,025	3,460,025	-	-	-	-	-
Remaining for gas and diesel		MWh		15,071,221	14,350,418	12,528,914	9,455,279	9,136,130	8,684,631	8,148,771	7,850,039	7,482,773	10,490,129	9,926,342	9,311,746	8,649,265	7,968,419
Existing CC capacity		MW		907	907	907	907	907	907	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711
Assumed CC maximum capacity factor	88%			88.0%	88.0%	88.0%	88.0%	88.0%	88.0%	54.4%	52.4%	49.9%	70.0%	66.2%	62.1%	57.7%	53.2%
Existing CC generation		MWh		6,991,882	6,991,882	6,991,882	6,991,882	6,991,882	6,991,882	8,148,771	7,850,039	7,482,773	10,490,129	9,926,342	9,311,746	8,649,265	7,968,419
Remaining for other peakers		MWh		8,079,339	7,358,536	5,537,032	2,463,397	2,144,248	1,692,750	0	-	-	-	-	-	-	0
Remaining capacity		MW		1,896	1,896	1,836	2,036	1,936	1,936	1,044	1,044	1,044	1,044	1,044	1,044	1,044	1,044
Implied capacity factor for remaining units		%		48.6%	44.3%	34.4%	13.8%	12.6%	10.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Average capacity factor		%		5.65%													
Spilled renewables		MWh		-	-	-	-	-	-	-	-	-	-	-	-	-	-
- Solar		MWh		-	-	-	-	-	-	-	-	-	-	-	-	-	-
- Wind		MWh		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar output utilized		MWh		242,827	242,827	1,013,707	2,597,106	2,328,827	2,845,653	3,186,136	3,334,823	3,628,201	3,791,169	3,894,285	3,977,702	3,967,893	3,958,493
Wind output utilized		MWh		221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190

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PREPA Rate Forecast Model - Generation Plan (3)

London Economics International LLC

Generation capacity and output summary table			unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Existing capacity			MW	4,731	3,871	3,251	3,791	4,071	3,971	3,971	3,883	4,083	4,083	3,629	3,629	3,629	3,629	3,629
ST Gas			MW	820	820	-	-	-	-	-	-	-	-	-	-	-	-	-
	generation in 2018		MWh	3,145,699	3,145,699													
	heat rate (Btu/kWh)		Btu/kWh	11,898	11,898													
	MMBtu		MMBtu	37,427,527	37,427,527													
ST Fuel oil			MW	1,532	632	632	532	532	432	432	-	-	-	-	-	-	-	-
	generation assumed		MWh		2,768,160	808,766	808,766	808,766	669,431	669,431								
	capacity factor		%		50.0%	14.6%	17.4%	17.4%	17.7%	17.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	MMBtu		MMBtu		24,794,409	8,728,250	8,728,250	8,728,250	7,480,226	7,480,226	-	-	-	-	-	-	-	-
CC Diesel			MW	920	520	520	520	520	520	520	60	60	60	60	60	60	60	60
GT Diesel			MW	744	744	744	784	984	984	984	984	984	984	984	984	984	984	984
	generation assumed		MWh	-	5,311,179	6,549,770	4,728,266	1,654,631	1,474,817	1,023,318	0	-	-	-	-	-	-	0
	capacity factor		%		48.6%	44.3%	34.4%	13.8%	12.6%	10.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	heat rate (Btu/kWh)	9,320	Btu/kWh	9,320	9,320	9,320	9,320	9,320	9,320	9,320	9,320	9,320	9,320	9,320	9,320	9,320	9,320	9,320
	MMBtu		MMBtu	-	49,500,192	61,043,857	44,067,439	15,421,157	13,745,290	9,537,326	0	-	-	-	-	-	-	0
Coal IPP			MW	454	454	454	454	454	454	454	454	454	454	-	-	-	-	-
CCGT Gas			MW	-	-	-	-	-	-	-	604	604	604	604	604	604	604	604
	generation assumed		MWh	-	-	-	-	-	-	-	2,876,597	2,771,142	2,641,493	3,703,120	3,504,097	3,287,139	3,053,277	2,812,931
	capacity factor				88%	88%	88%	88%	88%	88%	54%	52%	50%	70%	66%	62%	58%	53%
	heat rate (Btu/kWh)	assumed 10000	Btu/kWh								10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
	MMBtu		MMBtu	-	-	-	-	-	-	-	28,765,970	27,711,418	26,414,934	37,031,198	35,040,974	32,871,388	30,532,766	28,129,310
CC Gas converted			MW	-	400	400	400	400	400	400	600	600	600	600	600	600	600	600
	generation assumed		MWh		3083520	3083520	3083520	3083520	3083520	3083520	2857546.72	2752789.83	2624000.04	3678595.78	3480891.49	3265369.72	3033056.18	2794302.36
	heat rate (Btu/kWh)	IRP2019 Exhibit 8-42	Btu/kWh		7739	7739	7739	7739	7739	7739	7739	7739	7739	7739	7739	7739	7739	7739
	MMBtu		MMBtu		23,863,361	23,863,361	23,863,361	23,863,361	23,863,361	23,863,361	22,114,554	21,303,840	20,307,136	28,468,653	26,938,619	25,270,696	23,472,822	21,625,106
Solar			MW		126	126	326	837	1,023	1,250	1,451	1,591	1,737	1,852	1,936	2,000	2,030	2,042
Existing solar			MW	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126
derated Solar			MW	27.72	28	28	72	184	225	274.91	319.31	350	382	407	426	440	446	449
Existing wind			MW	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101
Wind			MW		-	-	-	-	-	-	-	-	-	-	-	-	-	-
derated Wind			MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydro			MW	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Batteries			MW	-	40	240	840	920	920	920	920	1120	1120	1120	1120	1120	1120	1120
Conventional IPPs			MW	961	961	961	961	961	961	961	961	961	961	507	507	507	507	507

Link to O&M generation reduction	MW	Type	Generation, N	$ O&M/kWh	$ million	Retirement year	COD
Aguirre Steam 1, 2	900		2,945,857	$ 0.0	$ -	2019	
Costa Sur 5 6	782		3,145,699	$ 0.0	$ 31.5	2020	
San Juan 8	100		139,335	$ 0.0	$ 1.4	2021	
GT Peakers	378		-	$ 0.2	$ -	2021	
San Juan 7	100		139,335	$ 0.0	$ 1.4	2023	
Aguirre CCGT 2	260		109,327	$ 0.0	$ 4.4	2025	
Palo Seco 3&4	301		466,433	$ -	$ -	2025	
San Juan 6	220		1,056,033	$ 0.0	$ 10.6	2025	
Additional potential retirements							COD
San Juan 9,10	200	Not modeled	278,670	$ 0.0	$ 2.8	2099	1969
Costa Sur 3 4	170	Not modeled	-	$ -	$ -	2099	1963
Culebra	2	Not modeled	9,344	$ -	$ -	2099	1972
Palo Seco 1&2	301	Not modeled	466,433	$ -	$ -	2099	1961
Cambalache GT 2,3	166	GT (Diesel)	81,788	$ 0.1	$ 4.1	2039	1977
Cambalache GT 1	83	Not modeled	-	$ -	$ -	2099	1977
Mayaguez 1	50	GT (Diesel)	31,218.00	$ 0.2	$ 5.6	2044	2009
Mayaguez 2	50	GT (Diesel)	31,218.00	$ 0.2	$ 5.6	2045	2009
Mayaguez 3	50	GT (Diesel)	31,218.00	$ 0.2	$ 5.6	2099	2009
Mayaguez 4	50	GT (Diesel)	31,218.00	$ 0.2	$ 5.6	2099	2009

O&M cost of existing units ($ million) - transformed

2019	2020	2021	2021	2023	2025	2025	2025
$ -	$ 31.46	$ 1.39	$ -	$ 1.39	$ 4.37	$ -	$ 10.56

Logic in determining retirement

1. Older units retire first
2. Keep the reserve margin requirement above target

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Retired MW	MW	-	900	1,682	2,160	2,160	2,260	2,260	3,041	3,041	3,041	3,041	3,041	3,041	3,041	3,041
Retired MWh	MWh	-	2,945,857	6,091,556	6,230,891	6,230,891	6,370,226	6,370,226	8,002,018	8,002,018	8,002,018	8,002,018	8,002,018	8,002,018	8,002,018	8,002,018
O&M saved	$ million	$ -	$ -	$ -	$ 31	$ 33	$ 33	$ 34	$ 34	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49

Historical generation, 2018

No.6 fuel oil	MWh	Average heat rate, B	MMBtu	Retirement
Aguirre 1&2	2,945,857	10,693	31,500,049	2019
Palo Seco 3&4	669,431	11,174	7,480,226	2025
San Juan 7 & 8	278,670	8957	2,496,047	2021/2023
Total			41,476,322	
Diesel	**Capacity factor**	**Average heat rate, Btu/kWh**		
Average	7%	13,180		

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PREPA Rate Forecast Model - Generation Plan cont.

London Economics International LLC

ICAP	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Total	MW	5606	5606	5606	5606	5524	5524	5524	5358	5358	5358	5358	5358	5308	5258	5258			
Existing Total	MW	1,799	1,799	1,799	1,799	1,799	1,799	1,799	1,633	1,633	1,633	1,633	1,633	1,583	1,533	1,533			
ST	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
Gas	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
Fuel oil #6	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
CC (Diesel)	MW	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660			
GT (Diesel)	MW	366	366	366	366	366	366	366	200	200	200	200	200	150	100	100			
Hydro	MW	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34			
IPP	MW	739	739	739	739	739	739	739	739	739	739	739	739	739	739	739			
AES Coal	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
EcoElectrica (CCGT)	MW	507	507	507	507	507	507	507	507	507	507	507	507	507	507	507			
Solar	MW	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126			
Wind	MW	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101			
Landfill Gas	MW	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5			
New additions in the ESM plan	MW	2342	2342	2342	2342	2260	2260	2260	2260	2260	2260	2260	2260	2260	2260	2260			
CCGT (Natural Gas)	MW	604	604	604	604	604	604	604	604	604	604	604	604	604	604	604			
Peakers diesel & gas	MW	618	618	618	618	618	618	618	618	618	618	618	618	618	618	618			
Solar	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
Wind	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
BESS	MW	1120	1120	1120	1120	1120	1120	1120	1120	1120	1120	1120	1120	1120	1120	1120			
CC Diesel convert to Gas	MW	(600)	(600)	(600)	(600)	(600)	(600)	(600)	(600)	(600)	(600)	(600)	(600)	(600)	(600)	(600)			
CC Diesel convert to Gas	MW	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600			
Additional retirement of Diesel CC & large GTs	MW	0	0	0	0	-82	(82)	(82)	(82)	(82)	(82)	(82)	(82)	(82)	(82)	(82)			
LEI modeled additional renewable to meet RPS	MW	1,465	1,465	1,465	1,465	1,465	1,465	1,465	1,465	1,465	1,465	1,465	1,465	1,465	1,465	1,465			
Accumulative RPS solar	MW	1,916	1,921	1,921	1,921	1,921	1,921	1,921	1,921	1,921	1,921	1,921	1,921	1,921	1,921	1,921			
Accumulative RPS wind	MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0			
Additional solar for that year only	MW	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
Additional wind for that year only	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
RPS Automatic buildup logic																			
RPS target milestones	%	0%	0%	40%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	60%
Previous milestone value	%	20%	20%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	60%
Previous milestone year	year	2025	2025	2035	2035	2035	2035	2035	2035	2035	2035	2035	2035	2035	2035	2035	2035	2035	2050
Next milestone value	%	40%	40%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
Next milestone year	year	2035	2035	2050	2050	2050	2050	2050	2050	2050	2050	2050	2050	2050	2050	2050	2050	2050	2050
Smoothed target	%	36%	38%	40%	41%	43%	44%	45%	47%	48%	49%	51%	52%	53%	55%	56%	57%	59%	60%
Total generation	MWh	11,575,161	10,942,623	10,379,665	9,833,776	9,292,493	8,852,975	8,558,134	8,323,609	8,107,285	7,902,757	7,682,726	7,470,440	7,260,970	7,051,350	6,849,391			
Total renewables required	MWh	4,167,058	4,158,197	4,151,866	4,064,628	3,964,797	3,895,309	3,879,687	3,884,351	3,891,497	3,898,693	3,892,581	3,884,629	3,872,517	3,854,738	3,835,659			
Ratio of new wind and solar																			
Solar	%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%			
Wind	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%			
Existing solar generation	MWh	242,827	242,827	242,827	242,827	242,827	242,827	242,827	242,827	242,827	242,827	242,827	242,827	242,827	242,827	242,827			
Existing wind generation	MWh	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190			
Incremental new renewable generation required	MWh	10,972	(8,861)	(15,192)	(102,430)	(202,261)	(271,749)	(287,371)	(282,707)	(275,561)	(268,365)	(274,477)	(282,429)	(294,541)	(312,320)	(331,399)			
Solar generation required	MWh	10,972	(8,861)	(15,192)	(102,430)	(202,261)	(271,749)	(287,371)	(282,707)	(275,561)	(268,365)	(274,477)	(282,429)	(294,541)	(312,320)	(331,399)			
Wind generation required	MWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
Existing solar installed capacity	MW	6	(5)	(8)	(53)	(105)	(141)	(149)	(147)	(143)	(139)	(142)	(147)	(153)	(162)	(172)			
Existing wind installed capacity	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
Solar capacity factor	%																		
Wind capacity factor	%																		

Confidential

PREPA Rate Forecast Model - Generation Plan (2) cont.

London Economics International LLC

Step 4 - add more capacity to meet Reserve Margin		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Additional MW needed to meet Reserve Margin	MW	(60)	(85)	(114)	(186)	(164)	(219)	(249)	(94)	(103)	(114)	(128)	(147)	(116)	(87)	(111)			
Additional Batteries	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
Additional Gas peakers	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
Total capacity needed	MW	4,334	4,310	4,281	4,209	4,149	4,093	4,064	4,052	4,044	4,033	4,019	4,000	3,981	3,959	3,936			
Cumulative batteries added	MW	536	536	536	536	536	536	536	536	536	536	536	536	536	536	536			
Cumulative gas peakers added	MW	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230			
Reserve margin (nameplate capacity)	%	124%	131%	138%	142%	147%	152%	156%	161%	165%	170%	175%	179%	184%	188%	193%			
Renewable target in PR	%	36%	38%	40%	41%	43%	44%	45%	47%	48%	49%	51%	52%	53%	55%	56%			
Reserve margin in Hawaii	%	156%	153%	152%	152%	151%	150%	150%	179%	176%	174%	172%	171%	194%					
Renewable target in Hawaii	%								70%					100%					
Peak load	MW	1934	1866	1800	1736	1679	1627	1586	1553	1524	1493	1463	1432	1403	1373	1343			
Peak load CAGR	%																		

Simplified supply stack

	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Demand	MWh	11,575,161	10,942,623	10,379,665	9,833,776	9,292,493	8,852,975	8,558,134	8,323,609	8,107,285	7,902,757	7,682,726	7,470,440	7,260,970	7,051,350	6,849,391			
Wind capacity	MW	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101			
Wind generation	MWh	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190			
Solar capacity	MW	2,053	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047			
Solar generation	MWh	3,956,840	3,945,868	3,945,868	3,945,868	3,945,868	3,945,868	3,945,868	3,945,868	3,945,868	3,945,868	3,945,868	3,945,868	3,945,868	3,945,868	3,945,868			
Hydro capacity	MWh	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34			
Hydro generation	MWh	37,838	37,838	37,838	37,838	37,838	37,838	37,838	37,838	37,838	37,838	37,838	37,838	37,838	37,838	37,838			
Landfill gas capacity	MW	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5			
Landfill gas generation	MWh	37,843	37,843	37,843	37,843	37,843	37,843	37,843	37,843	37,843	37,843	37,843	37,843	37,843	37,843	37,843			
Remaining for non-renewable units	MWh	7,321,450	6,699,884	6,136,926	5,591,037	5,049,754	4,610,236	4,315,394	4,080,870	3,864,546	3,660,018	3,439,986	3,227,701	3,018,231	2,808,610	2,606,652			
Coal capacity	MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
Assumed coal maximum capacity factor																			
Implied capacity factor for coal	%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%	87%			
Coal generation	MWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
Remaining for gas and diesel	MWh	7,321,450	6,699,884	6,136,926	5,591,037	5,049,754	4,610,236	4,315,394	4,080,870	3,864,546	3,660,018	3,439,986	3,227,701	3,018,231	2,808,610	2,606,652			
Existing CC capacity	MW	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711			
Assumed CC maximum capacity factor		48.8%	44.7%	40.9%	37.3%	33.7%	30.8%	28.8%	27.2%	25.8%	24.4%	23.0%	21.5%	20.1%	18.7%	17.4%			
Existing CC generation	MWh	7,321,450	6,699,884	6,136,926	5,591,037	5,049,754	4,610,236	4,315,394	4,080,870	3,864,546	3,660,018	3,439,986	3,227,701	3,018,231	2,808,610	2,606,652			
Remaining for other peakers	MWh	0	-	-	-	-	-	-	-	-	0	-	-	-	-	-			
Remaining capacity	MW	1,044	1,044	1,044	1,044	962	962	962	796	796	796	796	796	746	696	696			
Implied capacity factor for remaining units	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%			
Average capacity factor	%																		
Spilled renewables	MWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
- Solar	MWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
- Wind	MWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			
Solar output utilized	MWh	3,956,840	3,945,868	3,945,868	3,945,868	3,945,868	3,945,868	3,945,868	3,945,868	3,945,868	3,945,868	3,945,868	3,945,868	3,945,868	3,945,868	3,945,868			
Wind output utilized	MWh	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190	221,190			

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PREPA Rate Forecast Model - Generation Plan (3) cont.

London Economics International LLC

Generation capacity and output summary table		unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Existing capacity		MW	3,629	3,629	3,629	3,629	3,547	3,547	3,547	3,381	3,381	3,381	3,381	3,381	3,331	3,281	3,281
ST Gas		MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	generation in 2018	MWh															
	heat rate (Btu/kWh)	Btu/kWh															
	MMBtu	MMBtu															
ST Fuel oil		MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	generation assumed	MWh															
	capacity factor	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	MMBtu	MMBtu	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC Diesel		MW	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
GT Diesel		MW	984	984	984	984	902	902	902	736	736	736	736	736	686	636	636
	generation assumed	MWh	0	-	-	-	-	-	-	-	-	0	-	-	-	-	-
	capacity factor	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	heat rate (Btu/kWh)	Btu/kWh	9,320	9,320	9,320	9,320	9,320	9,320	9,320	9,320	9,320	9,320	9,320	9,320	9,320	9,320	9,320
	MMBtu	MMBtu	0	-	-	-	-	-	-	-	-	0	-	-	-	-	-
Coal IPP		MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCGT Gas		MW	604	604	604	604	604	604	604	604	604	604	604	604	604	604	604
	generation assumed	MWh	2,584,545	2,365,125	2,166,396	1,973,692	1,782,613	1,627,459	1,523,377	1,440,588	1,364,223	1,292,023	1,214,349	1,139,410	1,065,465	991,467	920,174
	capacity factor		49%	45%	41%	37%	34%	31%	29%	27%	26%	24%	23%	22%	20%	19%	17%
	heat rate (Btu/kWh)	Btu/kWh	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
	MMBtu	MMBtu	25,845,447	23,651,255	21,663,959	19,736,917	17,826,133	16,274,590	15,233,771	14,405,876	13,642,230	12,920,226	12,143,494	11,394,104	10,654,654	9,914,674	9,201,739
CC Gas converted		MW	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
	generation assumed	MWh	2567428.466	2349462.375	2152048.859	1960620.86	1770807.873	1616681.112	1513288.492	1431047.277	1355188.447	1283466.178	1206307.331	1131864.602	1058409.304	984901.3765	914080.0388
	heat rate (Btu/kWh)	Btu/kWh	7739	7739	7739	7739	7739	7739	7739	7739	7739	7739	7739	7739	7739	7739	7739
	MMBtu	MMBtu	19,869,329	18,182,489	16,654,706	15,173,245	13,704,282	12,511,495	11,711,340	11,074,875	10,487,803	9,932,745	9,335,612	8,759,500	8,191,030	7,622,152	7,074,065
Solar		MW	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047
Existing solar		MW	126	126	126	126	126	126	126	126	126	126	126	126	126	126	126
derated Solar		MW	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450
Existing wind		MW	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101
Wind		MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
derated Wind		MW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydro		MW	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Batteries		MW	1120	1120	1120	1120	1120	1120	1120	1120	1120	1120	1120	1120	1120	1120	1120
Conventional IPPs		MW	507	507	507	507	507	507	507	507	507	507	507	507	507	507	507

		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Retired MW	MW	3,041	3,041	3,041	3,041	3,041	3,041	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207
Retired MWh	MWh	8,002,018	8,002,018	8,002,018	8,002,018	8,002,018	8,002,018	8,083,806	8,083,806	8,083,806	8,083,806	8,083,806	8,083,806	8,083,806	8,083,806	8,083,806	8,083,806	8,083,806	8,083,806
O&M saved	$ million	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 53	$ 53	$ 53	$ 53	$ 53	$ 59	$ 65	$ 65	$ 65	$ 65	$ 65

Confidential

PREPA Rate Forecast Model - Demand - Total

London Economics International LLC

LEI Forecasted Demand	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total demand (GWh)	GWh		15,967	15,312	14,348	12,983	12,453	12,515	12,345	12,218	12,157	11,899	11,482	10,995	10,379	9,744
Residential	GWh		6,064	5,648	5,476	4,881	4,701	4,737	4,620	4,598	4,657	4,589	4,525	4,402	4,179	3,947
Commercial	GWh		7,465	7,195	6,775	6,359	6,028	5,900	5,735	5,546	5,372	5,172	4,919	4,635	4,326	4,007
Industrial	GWh		2,061	2,133	1,801	1,487	1,507	1,703	1,815	1,899	1,953	1,967	1,869	1,791	1,709	1,628
Agriculture	GWh		26	26	26	26	27	27	27	27	27	26	26	26	26	26
Lighting	GWh		315	275	234	194	153	112	112	113	112	110	107	105	103	101
Others	GWh		36	36	36	36	36	36	36	36	36	36	36	36	35	35
Revenue generation demand	GWh		15,967	15,312	14,348	12,983	12,453	12,515	12,345	12,218	12,157	11,899	11,482	10,995	10,379	9,744
Actual consumption			16,154	15,747	15,180	14,254	13,847	13,946	13,828	13,759	13,759	13,568	13,217	12,803	12,263	11,712
Non-technical losses	GWh		827	827	853	858	854	856	853	846	845	844	845	852	859	867
Technical losses	GWh		1,473	1,407	1,313	1,183	1,130	1,130	1,110	1,093	1,080	1,050	1,005	954	892	828
Auxiliary	GWh		751	751	751	751	751	751	751	751	751	751	751	751	751	751
PREPA own use	GWh		34	34	34	34	34	34	34	34	34	34	34	34	34	34
Total generation requirement	GWh		19,052	18,331	17,300	15,809	15,222	15,287	15,092	14,942	14,868	14,578	14,117	13,586	12,914	12,224

LEI Forecasted Peak Load	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total peak demand (MW)	MW		2,979	2,891	2,725	2,520	2,429	2,417	2,397	2,369	2,340	2,299	2,232	2,161	2,084	2,005
Residential	MW		1,049	1,036	1,023	1,013	1,003	995	988	982	975	969	963	954	946	938
Commercial	MW		1,206	1,139	1,092	1,017	959	935	908	878	849	817	776	730	679	628
Industrial	MW		288	296	206	110	103	132	148	160	167	169	156	145	133	122
Agriculture	MW		6	6	6	6	7	7	7	7	7	6	6	6	6	6
Lighting	MW		73	64	54	45	35	26	26	26	26	25	25	24	24	23
Others	MW		6	6	6	6	6	6	6	6	6	6	6	6	5	5
Losses and others	MW		352	345	337	323	316	316	314	311	309	306	301	296	289	283

Siemen IRP forecast	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Generation	GWh		*18353*	*18417*	*18471*	*18547*	*18615*	*18666*	*18691*	*18691*	*18644*	*18567*	*18399*	*18264*	*18146*	*18037*
Gross Generation after EE	GWh		*18324*	*17829*	*17529*	*17251*	*16964*	*16659*	*16375*	*16066*	*15708*	*15320*	*14839*	*14390*	*13958*	*13533*
Gross Generation after EE and Customer Owned generation	GWh		*18196*	*17410*	*16876*	*16028*	*15692*	*15333*	*14996*	*14630*	*14211*	*13755*	*13209*	*12687*	*12179*	*11670*
Gross Generation	MW		*2791*	*2799*	*2805*	*2815*	*2823*	*2829*	*2831*	*2830*	*2822*	*2810*	*2785*	*2765*	*2748*	*2731*
Gross Generation after EE	MW		*2791*	*2713*	*2669*	*2628*	*2586*	*2541*	*2503*	*2462*	*2414*	*2362*	*2297*	*2237*	*2179*	*2122*
Gross Generation after EE and Customer Owned generation	MW		*2791*	*2703*	*2632*	*2564*	*2440*	*2395*	*2357*	*2316*	*2268*	*2216*	*2151*	*2091*	*2033*	*1976*
Gross energy sales	GWh		*15301*	*14874*	*14617*	*14379*	*14133*	*13872*	*13628*	*13364*	*13057*	*12725*	*12311*	*11926*	*11556*	*11193*
Technical losses	GWh		*1412*	*1367*	*1338*	*1310*	*1283*	*1253*	*1225*	*1195*	*1160*	*1123*	*1078*	*1035*	*993*	*951*
loss as % of gross	%		9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	8%
Non-Technical Losses without EE	GWh		*827*	*830*	*832*	*836*	*839*	*841*	*842*	*843*	*840*	*837*	*829*	*822*	*817*	*812*
Non-Technical Losses with EE	GWh		*827*	*803*	*790*	*777*	*763*	*749*	*736*	*722*	*705*	*687*	*665*	*644*	*624*	*605*
loss as % of gross	%		5%													
Sales Forecast Scenarios after EE and Customer Generation, reference case	GWh		*15173*	*14455*	*13963*	*13156*	*12861*	*12546*	*12250*	*11928*	*11560*	*11160*	*10681*	*10223*	*9776*	*9329*
Sales Forecast Scenarios after EE and Customer Generation, low case	GWh		*14717*	*13927*	*13237*	*12345*	*12005*	*11603*	*11165*	*10813*	*10382*	*9931*	*9472*	*9064*	*8666*	*8337*
Sales Forecast Scenarios after EE and Customer Generation, very pessimistic case	GWh		*14575*	*13596*	*12876*	*11804*	*11265*	*10738*	*10266*	*9800*	*9333*	*8866*	*8400*	*7937*	*7482*	*7031*
Source	*IRP 2019 page 77*															

CFP 2019 demand forecast		2019
Total	GWh	*15963*
Residential	GWh	*6064*
Commercial	GWh	*7465*
Industrial	GWh	*2061*
Others	GWh	*373*

Confidential

PREPA Rate Forecast Model - Demand - Total cont.

London Economics International LLC

LEI Forecasted Demand	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total demand (GWh)	GWh	9,147	8,565	8,045	7,542	7,046	6,644	6,368	6,149	5,947	5,755	5,549	5,350	5,154	4,959	4,770
Residential	GWh	3,707	3,465	3,270	3,076	2,841	2,680	2,586	2,556	2,527	2,510	2,479	2,460	2,437	2,415	2,398
Commercial	GWh	3,710	3,418	3,133	2,854	2,598	2,352	2,166	1,978	1,796	1,615	1,436	1,255	1,077	899	723
Industrial	GWh	1,571	1,524	1,486	1,458	1,454	1,460	1,464	1,464	1,472	1,477	1,483	1,483	1,488	1,492	1,496
Agriculture	GWh	26	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Lighting	GWh	99	98	96	95	94	93	93	93	93	93	93	93	93	93	93
Others	GWh	35	35	35	34	34	34	34	34	34	34	34	34	34	34	34
Revenue generation demand	GWh	9,147	8,565	8,045	7,542	7,046	6,644	6,368	6,149	5,947	5,755	5,549	5,350	5,154	4,959	4,770
Actual consumption		11,196	10,701	10,272	9,867	9,465	9,165	8,889	8,670	8,468	8,276	8,070	7,871	7,675	7,480	7,291
Non-technical losses	GWh	875	883	892	900	904	907	910	911	913	916	917	919	921	922	924
Technical losses	GWh	768	709	657	607	558	516	495	478	462	447	431	416	401	385	371
Auxiliary	GWh	751	751	751	751	751	751	751	751	751	751	751	751	751	751	751
PREPA own use	GWh	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Total generation requirement	GWh	11,575	10,943	10,380	9,834	9,292	8,853	8,558	8,324	8,107	7,903	7,683	7,470	7,261	7,051	6,849
							-4.5%									

LEI Forecasted Peak Load	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total peak demand (MW)	MW	1,934	1,866	1,800	1,736	1,679	1,627	1,586	1,553	1,524	1,493	1,463	1,432	1,403	1,373	1,343
Residential	MW	929	921	912	903	894	885	876	876	876	876	876	876	876	876	876
Commercial	MW	579	532	485	440	398	358	328	298	268	239	209	180	151	122	94
Industrial	MW	114	107	102	98	97	98	99	99	100	101	101	101	102	103	103
Agriculture	MW	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Lighting	MW	23	23	22	22	22	22	22	22	22	22	22	22	22	22	22
Others	MW	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Losses and others	MW	277	271	267	262	256	252	250	248	247	245	244	242	240	239	237

Siemen IRP forecast	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Gross Generation	GWh	17938	17851	17775	17711	17657	17353									
Gross Generation after EE	GWh	13118	12713	12377	12052	11737	11429									
Gross Generation after EE and Customer Owned generation	GWh	11174	10682	10255	9831	9422	9012									
Gross Generation	MW	2716	2793	2692	2682	2673	2666									
Gross Generation after EE	MW	2067	2013	2970	2930	2890	1852									
Gross Generation after EE and Customer Owned generation	MW	1921	1867	1825	1784	1744	1706									
Gross energy sales	GWh	10838	10492	10207	9932	9665	9405									
Technical losses	GWh	910	869	834	799	765	731									
loss as % of gross	%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
Non-Technical Losses without EE	GWh	807	803	799	796	794	792									
Non-Technical Losses with EE	GWh	585	567	551	537	522	508									
loss as % of gross	%															
Sales Forecast Scenarios after EE and Customer Generation, reference case	GWh	8894	8461	8085	7711	7350	6989									
Sales Forecast Scenarios after EE and Customer Generation, low case	GWh	7999	7559	7148	6861	6495	6137									
Sales Forecast Scenarios after EE and Customer Generation, very pessimistic case	GWh	6592	6156	5770	5390	5027	4665									

Confidential

PREPA Rate Forecast Model - Demand - Residential

London Economics International LLC

	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Residential (GWh)	*GWh*	5,512	6,064	5,648	5,476	4,881	4,701	4,737	4,620	4,598	4,657	4,589	4,525	4,402	4,179	3,947
Total Residential peak demand (MW)	*MW*	942	1,049	1,036	1,023	1,013	1,003	995	988	982	975	969	963	954	946	938
Load factor		*66.8%*														
Source	IRP19 page 65															

Key Driver	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Population forecast	*thousands of people*	3,168	3,112	3,061	3,013	2,971	2,935	2,903	2,878	2,853	2,828	2,803	2,779	2,747	2,715	2,684
GNP forecast (Real Million US dollars)	*Real Million US dollars*	$ 56,900	$ 60,100	$ 61,000	$ 59,369	$ 58,289	$ 57,417	$ 57,651	$ 57,391	$ 57,177	$ 57,057	$ 56,873	$ 56,446	$ 55,924	$ 55,149	$ 54,182
GNP per capita	*Real US dollars*	$ 17,961	$ 19,312	$ 19,928	$ 19,704	$ 19,619	$ 19,563	$ 19,859	$ 19,943	$ 20,043	$ 20,176	$ 20,287	$ 20,312	$ 20,359	$ 20,312	$ 20,189
Correlation coefficient with population		*75.5%*														
Source	PREPA Load Forecast															
Inflation		2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Inflation index		1.00	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27	1.29	1.32

IRP EE	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
IRP's forecast before EE, before losses	*GWh*		*5,472*	*5,480*	*5,473*	*5,473*	*5,470*	*5,464*	*5,451*	*5,431*	*5,396*	*5,353*	*5,282*	*5,223*	*5,168*	*5,115*
IRP's forecast after EE, before losses	*GWh*		*5,472*	*5,226*	*5,145*	*5,070*	*4,992*	*4,910*	*4,821*	*4,724*	*4,612*	*4,491*	*4,343*	*4,203*	*4,068*	*3,935*
Source	IRP page 56															

Elasticity	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Electricity rates (proxy to residential rate)	*$/MWh*	$ -	$ 200	$ 278	$ 299	$ 286	$ 300	$ 298	$ 282	$ 287	$ 291	$ 303	$ 333	$ 369	$ 412	$ 459
Real change in rates	%			36.25%	5.30%	-6.06%	2.83%	-2.62%	-7.39%	-0.24%	-0.48%	1.96%	7.95%	8.62%	9.32%	9.30%
Residential demand price elasticity	*Long-run*	(0.32)														
Long-run demand change due to price elasticity																
2019	*GWh*				-	-	-	-	-	-	-	-	-	-	-	-
2020	*GWh*					(431)	(431)	(431)	(431)	(431)	(431)	(431)	(431)	(431)	(431)	(431)
2021	*GWh*						(24)	(24)	(24)	(24)	(24)	(24)	(24)	(24)	(24)	(24)
2022	*GWh*							186	186	186	186	186	186	186	186	186
2023	*GWh*								24	24	24	24	24	24	24	24
2024	*GWh*									123	123	123	123	123	123	123
2025	*GWh*										206	206	206	206	206	206
2026	*GWh*											81	81	81	81	81
2027	*GWh*												85	85	85	85
2028	*GWh*													45	45	45
2029	*GWh*														(56)	(56)
2030	*GWh*															(60)
2031	*GWh*															
2032	*GWh*															
2033	*GWh*															
2034	*GWh*															
2035	*GWh*															
2036	*GWh*															
2037	*GWh*															
2038	*GWh*															
2039	*GWh*															
2040	*GWh*															
2041	*GWh*															
2042	*GWh*															
2043	*GWh*															
2044	*GWh*															
2045	*GWh*															
2046	*GWh*															
Total	*GWh*		-	-	-	(431)	(455)	(269)	(245)	(123)	83	164	249	294	239	178

PREPA Rate Forecast Model - Demand - Residential (2)

London Economics International LLC

Customer owned generation	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Solar DG from IRP (derived)			(72)	(158)	(184)	(210)	(236)	(262)	(289)	(319)	(350)	(385)	(418)	(456)	(495)	(538)
Incremental DG			(72)	(86)	(26)	(26)	(26)	(26)	(27)	(30)	(31)	(34)	(34)	(38)	(39)	(43)
Solar LCOE (no battery)	*Nominal $/MWh*	$ 69	$ 67	$ 63	$ 64	$ 67	$ 78	$ 77	$ 76	$ 76	$ 75	$ 74	$ 73	$ 72	$ 72	$ 71
Electricity rates (proxy to residential rate)	*Nominal $/MWh*	$ -	$ 200	$ 278	$ 299	$ 286	$ 300	$ 298	$ 282	$ 287	$ 291	$ 303	$ 333	$ 369	$ 412	$ 459
% difference of Solar vs rate of previous year			-100.0%	217.6%	334.5%	345.7%	266.9%	289.8%	292.3%	270.6%	282.1%	293.1%	314.4%	362.7%	412.6%	479.6%
Conversion threshold		*100%*														
If rate is low, how much to discount conversion to DG		*50%*														
Modeled conversion GWh				(86)	(26)	(26)	(26)	(26)	(27)	(30)	(31)	(34)	(34)	(38)	(39)	(43)
Cumulative conversion to self-generation			(72)	(158)	(184)	(210)	(236)	(262)	(289)	(319)	(350)	(385)	(418)	(456)	(495)	(538)

LEI demand forecast	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
LEI adjusted residential forecast before EE, before losses and elasticity	*GWh*	5,512	6,136	6,060	5,988	5,925	5,871	5,822	5,784	5,746	5,708	5,671	5,633	5,584	5,535	5,487
LEI adjusted residential forecast before EE, before losses and elasticity, after DG		5,512	6,064	5,902	5,804	5,715	5,635	5,560	5,495	5,427	5,358	5,286	5,215	5,128	5,040	4,949
Long run demand elasticity			-	-	-	(431)	(455)	(269)	(245)	(123)	83	164	249	294	239	178
Implied EE	*GWh*		-	254	328	403	478	554	630	707	784	862	939	1,020	1,100	1,180
Incremental EE	*GWh*			254	74	75	75	76	76	77	77	78	77	81	80	80
LEI adjusted residential demand	*GWh*	5,512	6,064	5,648	5,476	4,881	4,701	4,737	4,620	4,598	4,657	4,589	4,525	4,402	4,179	3,947

Non-technical losses	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
IRP projected non-technical losses	*GWh*		827	830	832	836	839	841	842	843	840	837	829	822	817	812
IRP projected non-technical losses	*%*		15.1%	15.1%	15.2%	15.3%	15.3%	15.4%	15.4%	15.5%	15.6%	15.6%	15.7%	15.7%	15.8%	15.9%
LEI forecast using %	*GWh*		927	918	910	905	900	896	893	892	889	887	884	879	875	871
LEI forecast using regression	*GWh*		827	827	853	858	854	856	853	846	845	844	845	852	859	867

Parameters used for non-technical losses calculation

		FE Model-2 L'	FE Model-4 G	Average
PCY	Real GDP per capita	*-0.081*	*-0.154*	-0.1175
P(t)	Average electricity price	*0.079*	*0.114*	0.0965

Source: http //pide.org.pk/psde/pdf/AGM29/papers/Faisal%20jamil.pdf

Confidential

PREPA Rate Forecast Model - Demand - Residential cont.

London Economics International LLC

	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total Residential (GWh)	*GWh*	3,707	3,465	3,270	3,076	2,841	2,680	2,586	2,556	2,527	2,510	2,479	2,460	2,437	2,415	2,398
Total Residential peak demand (MW)	*MW*	929	921	912	903	894	885	876	876	876	876	876	876	876	876	876
Load factor																

Key Driver	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Population forecast	*thousands of people*	2,653	2,622	2,587	2,553	2,519	2,486	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453
GNP forecast (Real Million US dollars)	*Real Million US dollars*	$ 53,203	$ 52,134	$ 51,334	$ 50,569	$ 49,944	$ 49,453	$ 48,905	$ 48,610	$ 48,383	$ 48,185	$ 48,005	$ 47,816	$ 47,689	$ 47,566	$ 47,452
GNP per capita	*Real US dollars*	$ 20,056	$ 19,883	$ 19,841	$ 19,807	$ 19,825	$ 19,893	$ 19,937	$ 19,817	$ 19,724	$ 19,643	$ 19,570	$ 19,493	$ 19,441	$ 19,391	$ 19,344
Correlation coefficient with population																
Inflation		2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Inflation index		1.35	1.37	1.40	1.43	1.46	1.49	1.52	1.55	1.58	1.61	1.64	1.67	1.71	1.74	1.78

IRP EE	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
IRP's forecast before EE, before losses	*GWh*	*5,065*	*5,020*	*4,978*	*4,940*	*4,905*	*4,873*									
IRP's forecast after EE, before losses	*GWh*	*3,805*	*3,678*	*3,605*	*3,536*	*3,469*	*3,406*									

Elasticity	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Electricity rates (proxy to residential rate)	*$/MWh*	$ 511	$ 570	$ 633	$ 670	$ 712	$ 750	$ 781	$ 807	$ 841	$ 870	$ 902	$ 935	$ 965	$ 998	$ 1,037
Real change in rates	%	9.21%	9.30%	8.88%	3.81%	4.14%	3.35%	2.10%	1.21%	2.26%	1.35%	1.66%	1.59%	1.24%	1.34%	1.87%
Residential demand price elasticity	*Long-run*															
Long-run demand change due to price elasticity																
2019	*GWh*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2020	*GWh*	(431)	(431)	(431)	(431)	(431)	(431)	(431)	(431)	(431)	(431)	(431)	(431)	(431)	(431)	(431)
2021	*GWh*	(24)	(24)	(24)	(24)	(24)	(24)	(24)	(24)	(24)	(24)	(24)	(24)	(24)	(24)	(24)
2022	*GWh*	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186
2023	*GWh*	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
2024	*GWh*	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123
2025	*GWh*	206	206	206	206	206	206	206	206	206	206	206	206	206	206	206
2026	*GWh*	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81
2027	*GWh*	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
2028	*GWh*	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
2029	*GWh*	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)
2030	*GWh*	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)
2031	*GWh*	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)
2032	*GWh*		(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)	(67)
2033	*GWh*			(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)
2034	*GWh*				(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)
2035	*GWh*					(102)	(102)	(102)	(102)	(102)	(102)	(102)	(102)	(102)	(102)	(102)
2036	*GWh*						(25)	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(25)	(25)
2037	*GWh*							(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)
2038	*GWh*								(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
2039	*GWh*									(14)	(14)	(14)	(14)	(14)	(14)	(14)
2040	*GWh*										(2)	(2)	(2)	(2)	(2)	(2)
2041	*GWh*											(16)	(16)	(16)	(16)	(16)
2042	*GWh*												(4)	(4)	(4)	(4)
2043	*GWh*													(8)	(8)	(8)
2044	*GWh*														(7)	(7)
2045	*GWh*															(2)
2046	*GWh*															
Total	*GWh*	108	41	(23)	(82)	(184)	(209)	(236)	(251)	(265)	(267)	(283)	(287)	(295)	(301)	(304)

Confidential

PREPA Rate Forecast Model - Demand - Residential (2) cont.

London Economics International LLC

Customer owned generation	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Solar DG from IRP (derived)		(580)	(625)	(672)	(722)	(771)	(823)	(823)	(823)	(823)	(823)	(823)	(823)	(823)	(823)	(823)
Incremental DG		(42)	(45)	(47)	(50)	(48)	(53)	-	-	-	-	-	-	-	-	-
Solar LCOE (no battery)	*Nominal $/MWh*	$ 71	$ 70	$ 70	$ 69	$ 68	$ 68	$ 68	$ 68	$ 68	$ 68	$ 68	$ 68	$ 68	$ 68	$ 68
Electricity rates (proxy to residential rate)	*Nominal $/MWh*	$ 511	$ 570	$ 633	$ 670	$ 712	$ 750	$ 781	$ 807	$ 841	$ 870	$ 902	$ 935	$ 965	$ 998	$ 1,037
% difference of Solar vs rate of previous year		546.2%	630.1%	714.0%	817.0%	885.3%	946.6%	1003.3%	1049.1%	1086.2%	1137.3%	1179.1%	1226.3%	1274.4%	1319.2%	1367.0%
Modeled conversion GWh		(42)	(45)	(47)	(50)	(48)	(53)	-	-	-	-	-	-	-	-	-
Cumulative conversion to self-generation		(580)	(625)	(672)	(722)	(771)	(823)	(823)	(823)	(823)	(823)	(823)	(823)	(823)	(823)	(823)

LEI demand forecast	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
LEI adjusted residential forecast before EE, before losses and elasticity	*GWh*	5,439	5,392	5,338	5,284	5,231	5,179	5,127	5,127	5,127	5,127	5,127	5,127	5,127	5,127	5,127
LEI adjusted residential forecast before EE, before losses and elasticity, after DG		4,859	4,767	4,666	4,562	4,461	4,356	4,304	4,304	4,304	4,304	4,304	4,304	4,304	4,304	4,304
Long run demand elasticity		108	41	(23)	(82)	(184)	(209)	(236)	(251)	(265)	(267)	(283)	(287)	(295)	(301)	(304)
Implied EE	*GWh*	1,260	1,342	1,373	1,404	1,436	1,467	1,482	1,497	1,512	1,527	1,542	1,557	1,572	1,587	1,602
Incremental EE	*GWh*	80	82	31	31	32	31	*15*	*15*	*15*	*15*	*15*	*15*	*15*	*15*	*15*
LEI adjusted residential demand	*GWh*	3,707	3,465	3,270	3,076	2,841	2,680	2,586	2,556	2,527	2,510	2,479	2,460	2,437	2,415	2,398

Non-technical losses	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
IRP projected non-technical losses	*GWh*	807	803	799	796	794	792									
IRP projected non-technical losses	*%*	15.9%	16.0%	16.1%	16.1%	16.2%	16.3%	16.3%	16.3%	16.3%	16.3%	16.3%	16.3%	16.3%	16.3%	16.3%
LEI forecast using %	*GWh*	867	862	857	851	847	842	833	833	833	833	833	833	833	833	833
LEI forecast using regression	*GWh*	875	883	892	900	904	907	910	911	913	916	917	919	921	922	924

Confidential

PREPA Rate Forecast Model - Demand - Commercial

London Economics International LLC

	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Commercial (GWh)	GWh		7,465	7,195	6,775	6,359	6,028	5,900	5,735	5,546	5,372	5,172	4,919	4,635	4,326	4,007
Total Commercial peak demand (MW)	MW		1,206	1,139	1,092	1,017	959	935	908	878	849	817	776	730	679	628
Load factor		70.2%														
Source		IRP19 page 65														

Key Driver	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Services as % of GDP	%	49.1%														
Government % of GDP	%	12.2%														
Non-Govt Services as % of GDP	%	43.1%														
Source	CIA World Factbook															
FOMB GNP forecast	Real Millions US dollars	$ 56,900	$ 60,100	$ 61,000	$ 60,400	$ 60,500	$ 60,600	$ 60,900	$ 60,422	$ 59,948	$ 59,478	$ 59,011	$ 58,606	$ 58,340	$ 58,076	$ 57,814
% change	%		6%	1%	-1%	0.2%	0%	0%	-1%	-1%	-1%	-1%	-1%	0%	0%	0%
Commercial GNP	Real Millions US dollars	$ 24,529	$ 25,909	$ 26,297	$ 26,038	$ 26,081	$ 26,125	$ 26,254	$ 26,048	$ 25,843	$ 25,641	$ 25,439	$ 25,265	$ 25,150	$ 25,037	$ 24,923
Ln change				1.5%	-1.0%	0.2%	0.2%	0.5%	-0.8%	-0.8%	-0.8%	-0.8%	-0.7%	-0.5%	-0.5%	-0.5%
Energy intensity	GWh/Real Millions of US dollars		0.29	0.28	0.27	0.27	0.26	0.25	0.24	0.23	0.23	0.22	0.21	0.21	0.20	0.19
Correlation of energy and GNP ln change pre-EE		52.1%														

IRP EE	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
IRP forecast before EE, before losses	GWh		7,962	7,948	7,917	7,886	7,856	7,827	7,801	7,774	7,747	7,721	7,695	7,669	7,644	7,619
IRP forecast after EE, before losses	GWh		7,962	7,760	7,541	7,322	7,103	6,887	6,672	6,458	6,243	6,028	5,814	5,601	5,387	5,175
Source	IRP2019 page 56 and 57															
% change for gross demand				-0.18%	-0.39%	-0.39%	-0.38%	-0.37%	-0.33%	-0.35%	-0.35%	-0.34%	-0.34%	-0.34%	-0.33%	-0.33%
Level of EE	GWh		0	-188	-376	-564	-753	-940	-1129	-1316	-1504	-1693	-1881	-2068	-2257	-2444
Incremental EE	GWh		0	-188	-188	-188	-189	-187	-189	-187	-188	-189	-188	-187	-189	-187
CFP 2019 demand, adding back DG	GWh		7,565													
IRP forecast before EE, before losses, scaled	GWh		7,565	7,552	7,522	7,493	7,464	7,437	7,412	7,386	7,361	7,336	7,311	7,287	7,263	7,239
IRP forecast after EE, before losses, scaled	GWh		7,565	7,364	7,146	6,929	6,711	6,497	6,283	6,070	5,857	5,643	5,430	5,219	5,006	4,795
Ln change				-0.2%	-0.4%	-0.4%	-0.4%	-0.4%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%

Elasticity	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Electricity rates (proxy to commercial rate)	nominal $/MWh	$ -	$ 200	$ 278	$ 299	$ 286	$ 300	$ 298	$ 282	$ 287	$ 291	$ 303	$ 333	$ 369	$ 412	$ 459
Real change in rates	%			30.94%	5.17%	-6.25%	2.79%	-2.66%	-7.67%	-0.24%	-0.48%	1.94%	7.65%	8.27%	8.91%	8.89%
Demand elasticity		-0.34														
Implied change in demand			0.0%	0.0%	-10.0%	-1.7%	2.1%	-0.9%	0.9%	2.6%	0.1%	0.2%	-0.7%	-2.6%	-2.8%	-3.0%
2019	GWh			-	-	-										
2020	GWh				(233)	(233)	(233)									
2021	GWh					(38)	(38)	(38)								
2022	GWh						45	45	45							
2023	GWh							(19)	(19)	(19)						
2024	GWh								17	17	17					
2025	GWh									48	48	48				
2026	GWh										1	1	1			
2027	GWh											3	3	3		
2028	GWh												(11)	(11)	(11)	
2029	GWh													(40)	(40)	(40)
2030	GWh														(41)	(41)
2031	GWh															(41)
2032	GWh															
2033	GWh															
2034	GWh															
2035	GWh															
2036	GWh															
2037	GWh															
2038	GWh															
2039	GWh															
2040	GWh															
2041	GWh															
2042	GWh															
2043	GWh															
2044	GWh															
2045	GWh															
2046	GWh															
Total	GWh	0	-	-	(233)	(272)	(227)	(12)	43	47	67	53	(7)	(48)	(92)	(122)

Confidential

PREPA Rate Forecast Model - Demand - Commercial (2)

London Economics International LLC

Customer owned generation	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
DG Solar	*GWh*		(49)	(49)	(244)	(244)	(244)	(247)	(272)	(300)	(330)	(362)	(395)	(430)	(467)	(508)
Source	*IRP 2019, derived*															
Incremental DG solar	*GWh*		(49)	-	(195)	-	-	(3)	(25)	(28)	(30)	(33)	(32)	(35)	(37)	(41)
Incremental DG solar as % of demand			-0.6%	0.0%	-2.6%	0.0%	0.0%	0.0%	-0.4%	-0.4%	-0.5%	-0.5%	-0.6%	-0.6%	-0.7%	-0.8%
DG CHP	*GWh*		(51)	(189)	(60)	(103)	(128)	(148)	(148)	(148)	(148)	(148)	(148)	(148)	(148)	(148)
Source	*IRP 2019, derived*															
Incremental CHP	*GWh*		(51)	(138)	129	(43)	(25)	(20)	-	-	-	-	-	-	-	-
Incremental CHP solar as % of demand			-1%	-2%	2%	-1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
CHP	*GWh*	117	110	113	113	114	115	115	117	118	118	120	121	121	123	125
Battery Storage LCOE (Calculated)	*GWh*	177	173	167	166	167	176	174	171	170	167	164	162	159	158	155
% difference of CHP vs rate' of previous year			-100.0%	77.2%	146.1%	161.7%	148.3%	160.0%	155.5%	138.7%	142.4%	143.3%	150.0%	174.3%	200.0%	230.0%
% difference of Solar vs rate of previous year			-100.0%	20.1%	67.7%	78.7%	62.2%	72.7%	74.2%	66.1%	71.6%	76.8%	86.9%	109.0%	133.8%	164.9%
Conversion threshold		100%														
If rate is low, how much to discount conversion to DG		50%														
Modeled CHP DG																
Modeled conversion GWh	*GWh*			(69)	129	(43)	(25)	(20)	-	-	-	-	-	-	-	-
Culmulative conversion to self-genreation	*GWh*		(51)	(120)	9	(34)	(59)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)
Modeled Solar DG																
Modeled incremental conversion rate				-0.9%	0.9%	-0.3%	-0.2%	-0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Modeled conversion GWh	*GWh*			-	(98)	-	-	(2)	(13)	(14)	(15)	(16)	(16)	(35)	(37)	(41)
Culmulative conversion to self-genreation	*GWh*		(49)	(49)	(147)	(147)	(147)	(148)	(161)	(175)	(189)	(206)	(222)	(257)	(294)	(335)

LEI demand forecast	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Previous year's adjusted commericial GNP	*Real Millions US dollars*		$ 24,529	$ 25,909	$ 26,297	$ 25,596	$ 25,105	$ 24,687	$ 24,783	$ 24,682	$ 24,593	$ 24,553	$ 24,484	$ 24,300	$ 24,069	$ 23,721
Current year commercial GNP due to economic development	*Real Millions US dollars*		$ 25,909	$ 26,297	$ 26,038	$ 25,638	$ 25,147	$ 24,809	$ 24,588	$ 24,488	$ 24,400	$ 24,360	$ 24,316	$ 24,190	$ 23,960	$ 23,614
Base demand from commercial activities	*GWh*		7,565	7,364	7,146	6,811	6,460	6,139	5,931	5,752	5,573	5,404	5,226	5,019	4,791	4,543
Base demand from commercial activities less CHP	*GWh*		7,514	7,244	7,155	6,777	6,401	6,060	5,852	5,673	5,494	5,325	5,147	4,940	4,712	4,464
Base demand from commercial activities less CHP less solar	*GWh*		7,465	7,195	7,009	6,631	6,255	5,912	5,691	5,498	5,305	5,119	4,926	4,683	4,418	4,129
Change in demand due to price elasticity	*GWh*		-	-	(233)	(272)	(227)	(12)	43	47	67	53	(7)	(48)	(92)	(122)
Non-self-gen demand after elasticity impact	*GWh*		7,465	7,195	6,775	6,359	6,028	5,900	5,735	5,546	5,372	5,172	4,919	4,635	4,326	4,007
Total commercial demand	*GWh*		7,565	7,364	6,913	6,539	6,233	6,127	5,974	5,799	5,640	5,456	5,220	4,971	4,699	4,421
Demand-GNP impact coefficient		52%														
Commercial GNP impacted by demand change	*Real Millions US dollars*		$ -	$ -	$ (443)	$ (533)	$ (460)	$ (26)	$ 94	$ 104	$ 153	$ 124	$ (16)	$ (121)	$ (239)	$ (330)
Commercial GNP after demand impact	*Real Millions US dollars*	$ 24,529	$ 25,909	$ 26,297	$ 25,596	$ 25,105	$ 24,687	$ 24,783	$ 24,682	$ 24,593	$ 24,553	$ 24,484	$ 24,300	$ 24,069	$ 23,721	$ 23,284

Confidential

PREPA Rate Forecast Model - Demand - Commercial cont.

London Economics International LLC

	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total Commercial (GWh)	GWh	3,710	3,418	3,133	2,854	2,598	2,352	2,166	1,978	1,796	1,615	1,436	1,255	1,077	899	723
Total Commercial peak demand (MW)	MW	579	532	485	440	398	358	328	298	268	239	209	180	151	122	94
Load factor																

Key Driver	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Services as % of GDP	%															
Government % of GDP	%															
Non-Govt Services as % of GDP	%															
Source	CIA World Factbook															
FOMB GNP forecast	Real Millions US dollars	$ 57,552	$ 57,179	$ 57,071	$ 56,963	$ 56,856	$ 56,749	$ 56,420	$ 56,332	$ 56,244	$ 56,156	$ 56,068	$ 55,981	$ 55,945	$ 55,909	$ 55,873
% change	%	0%	-1%	0%	0%	0%	0%	-1%	0%	0%	0%	0%	0%	0%	0%	0%
Commercial GNP	Real Millions US dollars	$ 24,810	$ 24,650	$ 24,603	$ 24,557	$ 24,511	$ 24,464	$ 24,323	$ 24,285	$ 24,247	$ 24,209	$ 24,171	$ 24,133	$ 24,118	$ 24,102	$ 24,087
Ln change		-0.5%	-0.6%	-0.2%	-0.2%	-0.2%	-0.2%	-0.6%	-0.2%	-0.2%	-0.2%	-0.2%	-0.2%	-0.1%	-0.1%	-0.1%
Energy intensity	GWh/Real Millions of US dollars	0.18	0.18	0.17	0.16	0.15	0.14	0.14	0.13	0.12	0.11	0.10	0.10	0.09	0.08	0.07

IRP EE	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
IRP forecast before EE, before losses	GWh	7,596	7,572	7,549	7,527	7,506	7,484	7,462	7,440	7,418	7,397	7,375	7,354	7,332	7,311	7,289
IRP forecast after EE, before losses	GWh	4,963	4,752	4,541	4,331	4,121	3,912	3,703	3,494	3,285	3,077	2,868	2,660	2,451	2,243	2,034
Source	IRP2019 page 56 and 57															
% change for gross demand		-0.30%	-0.32%	-0.30%	-0.29%	-0.28%	-0.29%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Level of EE	GWh	-2633	-2820	-3008	-3196	-3385	-3572	-3759	-3946	-4133	-4320	-4507	-4694	-4881	-5068	-5255
Incremental EE	GWh	-189	-187	-188	-188	-189	-187	-187	-187	-187	-187	-187	-187	-187	-187	-187
CFP 2019 demand, adding back DG	GWh															
IRP forecast before EE, before losses, scaled	GWh	7,217	7,194	7,173	7,152	7,132	7,111	7,090	7,069	7,048	7,028	7,007	6,987	6,967	6,946	6,926
IRP forecast after EE, before losses, scaled	GWh	4,584	4,374	4,165	3,956	3,747	3,539	3,331	3,123	2,915	2,708	2,500	2,293	2,086	1,878	1,671
Ln change		-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%

Elasticity	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Electricity rates (proxy to commercial rate)	nominal $/MWh	$ 511	$ 570	$ 633	$ 670	$ 712	$ 750	$ 781	$ 807	$ 841	$ 870	$ 902	$ 935	$ 965	$ 998	$ 1,037
Real change in rates	%	8.81%	8.89%	8.51%	3.74%	4.06%	3.29%	2.08%	1.20%	2.24%	1.34%	1.65%	1.58%	1.23%	1.33%	1.85%
Demand elasticity																
Implied change in demand		-3.0%	-3.0%	-3.0%	-2.9%	-1.3%	-1.4%	-1.1%	-0.7%	-0.4%	-0.8%	-0.5%	-0.6%	-0.5%	-0.4%	-0.5%

		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
2019	GWh															
2020	GWh															
2021	GWh															
2022	GWh															
2023	GWh															
2024	GWh															
2025	GWh															
2026	GWh															
2027	GWh															
2028	GWh															
2029	GWh															
2030	GWh	(41)														
2031	GWh	(41)	(41)													
2032	GWh	(38)	(38)	(38)												
2033	GWh		(35)	(35)	(35)											
2034	GWh			(32)	(32)	(32)										
2035	GWh				(28)	(28)	(28)									
2036	GWh					(11)	(11)	(11)								
2037	GWh						(11)	(11)	(11)							
2038	GWh							(8)	(8)	(8)						
2039	GWh								(5)	(5)	(5)					
2040	GWh									(2)	(2)	(2)				
2041	GWh										(4)	(4)	(4)			
2042	GWh											(2)	(2)	(2)		
2043	GWh												(2)	(2)	(2)	
2044	GWh													(2)	(2)	(2)
2045	GWh														(1)	(1)
2046	GWh															(1)
Total	GWh	(120)	(114)	(105)	(95)	(71)	(50)	(30)	(24)	(15)	(11)	(9)	(9)	(6)	(6)	(4)

Confidential

PREPA Rate Forecast Model - Demand - Commercial (2) cont.

London Economics International LLC

Customer owned generation	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
DG Solar	*GWh*	(547)	(589)	(633)	(681)	(726)	(776)	(776)	(776)	(776)	(776)	(776)	(776)	(776)	(776)	(776)
Source	*IRP 2019, derived*															
Incremental DG solar	*GWh*	(39)	(42)	(44)	(48)	(46)	(49)	-	-	-	-	-	-	-	-	-
Incremental DG solar as % of demand		-0.8%	-0.9%	-1.0%	-1.1%	-1.1%	-1.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
DG CHP	*GWh*	(148)	(148)	(148)	(148)	(148)	(148)	(148)	(148)	(148)	(148)	(148)	(148)	(148)	(148)	(148)
Source	*IRP 2019, derived*															
Incremental CHP	*GWh*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Incremental CHP solar as % of demand		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
CHP	*GWh*	125	127	129	130	132	134	134	137	139	140	143	145	146	149	152
Battery Storage LCOE (Calculated)	*GWh*	154	152	150	148	146	145	144	143	142	141	141	140	139	139	138
% difference of CHP vs rate' of previous year		266.4%	302.4%	342.0%	388.3%	409.2%	432.4%	457.9%	471.4%	479.9%	500.5%	509.9%	521.2%	538.5%	547.2%	556.4%
% difference of Solar vs rate of previous year		198.1%	237.0%	278.8%	327.1%	359.1%	391.7%	421.6%	446.5%	467.2%	494.8%	518.1%	544.3%	571.1%	596.6%	623.7%
Conversion threshold																
If rate is low, how much to discount conversion to DG																
Modeled CHP DG																
Modeled conversion GWh	*GWh*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Culmulative conversion to self-genreation	*GWh*	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)	(79)
Modeled Solar DG																
Modeled incremental conversion rate		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Modeled conversion GWh	*GWh*	(39)	(42)	(44)	(48)	(46)	(49)	-	-	-	-	-	-	-	-	-
Culmulative conversion to self-genreation	*GWh*	(374)	(416)	(461)	(508)	(554)	(603)	(603)	(603)	(603)	(603)	(603)	(603)	(603)	(603)	(603)

LEI demand forecast	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Previous year's adjusted commericial GNP	*Real Millions US dollars*	$ 23,284	$ 22,840	$ 22,358	$ 21,993	$ 21,645	$ 21,361	$ 21,140	$ 20,902	$ 20,773	$ 20,674	$ 20,589	$ 20,513	$ 20,433	$ 20,381	$ 20,331
Current year commercial GNP due to economic development	*Real Millions US dollars*	$ 23,178	$ 22,692	$ 22,316	$ 21,952	$ 21,604	$ 21,321	$ 21,017	$ 20,869	$ 20,740	$ 20,641	$ 20,557	$ 20,481	$ 20,420	$ 20,368	$ 20,318
Base demand from commercial activities	*GWh*	4,283	4,027	3,777	3,536	3,302	3,084	2,878	2,684	2,494	2,309	2,127	1,946	1,766	1,587	1,409
Base demand from commercial activities less CHP	*GWh*	4,204	3,948	3,698	3,457	3,223	3,005	2,799	2,605	2,415	2,230	2,048	1,867	1,687	1,508	1,330
Base demand from commercial activities less CHP less solar	*GWh*	3,830	3,532	3,238	2,949	2,670	2,402	2,196	2,002	1,812	1,627	1,444	1,264	1,084	905	727
Change in demand due to price elasticity	*GWh*	(120)	(114)	(105)	(95)	(71)	(50)	(30)	(24)	(15)	(11)	(9)	(9)	(6)	(6)	(4)
Non-self-gen demand after elasticity impact	*GWh*	3,710	3,418	3,133	2,854	2,598	2,352	2,166	1,978	1,796	1,615	1,436	1,255	1,077	899	723
Total commercial demand	*GWh*	4,163	3,913	3,673	3,441	3,231	3,034	2,848	2,660	2,478	2,298	2,118	1,937	1,759	1,582	1,405
Demand-GNP impact coefficient																
Commercial GNP impacted by demand change	*Real Millions US dollars*	$ (338)	$ (334)	$ (323)	$ (307)	$ (243)	$ (181)	$ (115)	$ (97)	$ (66)	$ (53)	$ (44)	$ (47)	$ (39)	$ (37)	$ (32)
Commercial GNP after demand impact	*Real Millions US dollars*	$ 22,840	$ 22,358	$ 21,993	$ 21,645	$ 21,361	$ 21,140	$ 20,902	$ 20,773	$ 20,674	$ 20,589	$ 20,513	$ 20,433	$ 20,381	$ 20,331	$ 20,286

Confidential

PREPA Rate Forecast Model - Demand - Industrial

London Economics International LLC

	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Industrial	GWh		2,061	2,133	1,801	1,487	1,507	1,703	1,815	1,899	1,953	1,967	1,869	1,791	1,709	1,628
Total Instudtial peak demand (MW)	MW		288	296	206	110	103	132	148	160	167	169	156	145	133	122
Load factor		81.2%														
Source		IRP19 page 65														
Base industrial demand	GWh															
CFP 2019 demand, adding back DG			2,076													
IRP forecast before EE, before losses, scaled	GWh		2,076	2,160	2,276	2,421	2,537	2,645	2,729	2,796	2,824	2,829	2,762	2,723	2,697	2,675
IRP forecast after EE, before losses, scaled	GWh		2,076	2,160	2,276	2,409	2,537	2,645	2,729	2,796	2,824	2,829	2,762	2,723	2,697	2,675
Key Driver	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Industrial as % of GDP	%	50%														
Government % of GDP	%	12%														
Non-govt Industrial as % of GDP	%	44%														
Source	CIA world factbook															
FOMB GNP forecast	Real Millions US dollars	$ 56,900	$ 60,100	$ 61,000	$ 60,400	$ 60,500	$ 60,600	$ 60,900	$ 60,422	$ 59,948	$ 59,478	$ 59,011	$ 58,606	$ 58,340	$ 58,076	$ 57,814
% change	%		5.6%	1.5%	-1.0%	0.2%	0.2%	0.5%	-0.8%	-0.8%	-0.8%	-0.8%	-0.7%	-0.5%	-0.5%	-0.5%
Industrial GNP	Real Millions US dollars	$ 25,029	$ 26,437	$ 26,833	$ 26,569	$ 26,613	$ 26,657	$ 26,789	$ 26,578	$ 26,370	$ 26,163	$ 25,958	$ 25,779	$ 25,663	$ 25,547	$ 25,431
% change			5.6%	1.5%	-1.0%	0.2%	0.2%	0.5%	-0.8%	-0.8%	-0.8%	-0.8%	-0.7%	-0.5%	-0.5%	-0.5%
Energy intensity	GWh/Real Millions of US dollars		0.0785	0.0805	0.0857	0.0905	0.0952	0.0988	0.1027	0.1060	0.1079	0.1090	0.1072	0.1061	0.1056	0.1052
Correlation of energy and GNP ln change pre-EE		35%														
IRP EE	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
IRP forecast before EE, before losses	GWh		1491	1551	1635	1739	1822	1900	1960	2008	2028	2032	1984	1956	1937	1921
IRP forecast after EE, before losses	GWh		1491	1551	1635	1730	1822	1900	1960	2008	2028	2032	1984	1956	1937	1921
Source	IRP19 page 56 and 57															
% change in gross demand				4.0%	5.4%	6.4%	4.8%	4.3%	3.2%	2.4%	1.0%	0.2%	-2.4%	-1.4%	-1.0%	-0.8%
Elasticity	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Electricity rates (proxy to industrial rate)	$/MWh	$ -	$ 200	$ 278	$ 299	$ 286	$ 300	$ 298	$ 282	$ 287	$ 291	$ 303	$ 333	$ 369	$ 412	$ 459
Real change in rate				30.94%	5.17%	-6.25%	2.79%	-2.66%	-7.67%	-0.24%	-0.48%	1.94%	7.65%	8.27%	8.91%	8.89%
% difference of CHP vs rate of previous year	%	N/A	-100%	77%	146%	162%	148%	160%	156%	139%	142%	143%	150%	174%	200%	230%
Demand elasticity		-0.81														
Implied change in demand			0.0%	0.0%	-22.2%	-4.1%	5.2%	-2.2%	2.2%	6.4%	0.2%	0.4%	-1.6%	-6.0%	-6.5%	-7.0%
2019	GWh			-	-	-										
2020	GWh				(144)	(144)	(144)									
2021	GWh					(23)	(23)	(23)								
2022	GWh						28	28	28							
2023	GWh							(13)	(13)	(13)						
2024	GWh								13	13	13					
2025	GWh									40	40	40				
2026	GWh										1	1	1			
2027	GWh											2	2	2		
2028	GWh												(10)	(10)	(10)	
2029	GWh													(37)	(37)	(37)
2030	GWh														(39)	(39)
2031	GWh															(40)
2032	GWh															
2033	GWh															
2034	GWh															
2035	GWh															
2036	GWh															
2037	GWh															
2038	GWh															
2039	GWh															
2040	GWh															
2041	GWh															
2042	GWh															
2043	GWh															
2044	GWh															
2045	GWh															
2046	GWh															
Total	GWh	-	-	-	(143.7)	(166.3)	(137.8)	(6.9)	28.7	40.0	53.9	43.4	(6.0)	(44.0)	(85.2)	(116.0)

PREPA Rate Forecast Model - Demand - Industrial (2)

London Economics International LLC

Customer owned generation	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Solar LCOE (Shown in IRP)	*$/MWh*	$ 69	$ 67	$ 63	$ 64	$ 67	$ 78	$ 77	$ 76	$ 76	$ 75	$ 74	$ 73	$ 72	$ 72	$ 71
Solar (Utility-Scale) LCOE (Calculated)	*$/MWh*	$ 73	$ 71	$ 71	$ 70	$ 70	$ 69	$ 69	$ 95	$ 94	$ 93	$ 92	$ 91	$ 90	$ 91	$ 91
Wind (Utility-Scale) LCOE (Calculated)	*$/MWh*	$ 111	$ 112	$ 112	$ 114	$ 115	$ 116	$ 118	$ 161	$ 163	$ 165	$ 167	$ 169	$ 172	$ 174	$ 176
CCGT LCOE (Calculated)	*$/MWh*	$ 80	$ 76	$ 78	$ 79	$ 80	$ 82	$ 83	$ 84	$ 85	$ 86	$ 87	$ 89	$ 90	$ 92	$ 93
CHP	*$/MWh*	$ 117	$ 110	$ 113	$ 113	$ 114	$ 115	$ 115	$ 117	$ 118	$ 118	$ 120	$ 121	$ 121	$ 123	$ 125
Battery Storage LCOE (Calculated)	*$/MWh*	$ 108	$ 106	$ 104	$ 102	$ 100	$ 98	$ 97	$ 95	$ 94	$ 92	$ 90	$ 89	$ 87	$ 86	$ 84
Suitable LCOE for self-generation	*$/MWh*	$ 177	$ 173	$ 167	$ 166	$ 167	$ 176	$ 174	$ 171	$ 170	$ 167	$ 164	$ 162	$ 159	$ 158	$ 155
IRP forecasted self generation	*GWh*		-128	-419	-653	-1223	-1272	-1326	-1379	-1436	-1497	-1565	-1630	-1703	-1779	-1863
IRP Incremental self generation				-291	-234	-570	-49	-54	-53	-57	-61	-68	-65	-73	-76	-84
Demand converted to self generation	*GWh*		(15)	(39)	(344)	(714)	(786)	(774)	(774)	(774)	(774)	(774)	(774)	(774)	(774)	(774)
Imcremental conversion	*GWh*		(15)	(24)	(305)	(370)	(72)	12	-	-	-	-	-	-	-	-
Conversion rate as % of demand in IRP			1.0%	1.5%	18.7%	21.4%	4.0%	-0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Conversion threshold		*100%*														
If rate is low, how much to discount conversion to DG		*50%*														
Modeled conversion GWh				(12)	(305)	(370)	(72)	12	-	-	-	-	-	-	-	-
Culmulative conversion to self-genreation			(15)	(27)	(332)	(702)	(774)	(762)	(762)	(762)	(762)	(762)	(762)	(762)	(762)	(762)
GDP from self-generation industries			$ 191	$ 485	$ 4,015	$ 7,888	$ 8,259	$ 7,838	$ 7,538	$ 7,300	$ 7,171	$ 7,101	$ 7,223	$ 7,293	$ 7,332	$ 7,359

LEI demand forecast	unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Previous year's adjusted industrial GNP	*Real Millions US dollars*		$ 25,029	$ 26,437	$ 26,833	$ 25,980	$ 25,378	$ 24,912	$ 25,011	$ 24,913	$ 24,849	$ 24,830	$ 24,775	$ 24,585	$ 24,328	$ 23,934
Current year industrial GNP due to economic dev	*Real Millions US dollars*		$ 26,437	$ 26,833	$ 26,569	$ 26,023	$ 25,420	$ 25,035	$ 24,814	$ 24,717	$ 24,654	$ 24,635	$ 24,605	$ 24,474	$ 24,218	$ 23,826
Base demand from industrial activities	*GWh*		2,076	2,160	2,276	2,355	2,419	2,472	2,548	2,621	2,661	2,685	2,637	2,597	2,557	2,506
Demand not yet converted to self generation	*GWh*		2,061	2,133	1,944	1,653	1,645	1,710	1,786	1,859	1,899	1,923	1,875	1,835	1,795	1,744
Change in demand due to price elasticity	*GWh*		-	-	(144)	(166)	(138)	(7)	29	40	54	43	(6)	(44)	(85)	(116)
Non-self-gen demand after elasticity impact	*GWh*		2,061	2,133	1,801	1,487	1,507	1,703	1,815	1,899	1,953	1,967	1,869	1,791	1,709	1,628
Total industrial demand	*GWh*		2,076	2,160	2,133	2,189	2,281	2,465	2,577	2,661	2,715	2,729	2,631	2,553	2,471	2,390
Demand-GNP impact coefficient		35%														
Industrial GNP impacted by demand change	*Real Millions US dollars*		$ -	$ -	$ (589)	$ (645)	$ (508)	$ (24)	$ 98	$ 132	$ 175	$ 140	$ (20)	$ (146)	$ (283)	$ (387)
Industrial GNP after demand impact	*Real Millions US dollars*	$ 25,029	$ 26,437	$ 26,833	$ 25,980	$ 25,378	$ 24,912	$ 25,011	$ 24,913	$ 24,849	$ 24,830	$ 24,775	$ 24,585	$ 24,328	$ 23,934	$ 23,439

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PREPA Rate Forecast Model - Demand - Industrial cont.

London Economics International LLC

	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total Industrial	GWh	1,571	1,524	1,486	1,458	1,454	1,460	1,464	1,464	1,472	1,477	1,483	1,483	1,488	1,492	1,496
Total Instudtial peak demand (MW)	MW	114	107	102	98	97	98	99	99	100	101	101	101	102	103	103
Load factor																
Base industrial demand	GWh															
CFP 2019 demand, adding back DG																
IRP forecast before EE, before losses, scaled	GWh	2,659	2,652	2,652	2,661	2,675	2,694	2,701	2,711	2,723	2,736	2,748	2,759	2,771	2,783	2,795
IRP forecast after EE, before losses, scaled	GWh	2,659	2,652	2,652	2,661	2,675	2,694	2,701	2,711	2,723	2,736	2,748	2,759	2,771	2,783	2,795

Key Driver	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Industrial as % of GDP	%															
Government % of GDP	%															
Non-govt Industrial as % of GDP	%															
Source	CIA world factbook															
FOMB GNP forecast	Real Millions US dollars	$ 57,552	$ 57,179	$ 57,071	$ 56,963	$ 56,856	$ 56,749	$ 56,420	$ 56,332	$ 56,244	$ 56,156	$ 56,068	$ 55,981	$ 55,945	$ 55,909	$ 55,873
% change	%	-0.5%	-0.6%	-0.2%	-0.2%	-0.2%	-0.2%	-0.6%	-0.2%	-0.2%	-0.2%	-0.2%	-0.2%	-0.1%	-0.1%	-0.1%
Industrial GNP	Real Millions US dollars	$ 25,316	$ 25,152	$ 25,104	$ 25,057	$ 25,010	$ 24,963	$ 24,818	$ 24,779	$ 24,740	$ 24,702	$ 24,663	$ 24,625	$ 24,609	$ 24,593	$ 24,577
% change		-0.5%	-0.6%	-0.2%	-0.2%	-0.2%	-0.2%	-0.6%	-0.2%	-0.2%	-0.2%	-0.2%	-0.2%	-0.1%	-0.1%	-0.1%
Energy intensity	GWh/Real Millions of US dollars	0.1050	0.1055	0.1057	0.1062	0.1069	0.1079	0.1088	0.1094	0.1101	0.1107	0.1114	0.1120	0.1126	0.1131	0.1137

IRP EE	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
IRP forecast before EE, before losses	GWh	1910	1905	1905	1911	1921	1935	1,940	1,947	1,956	1,965	1,974	1,981	1,990	1,998	2,007
IRP forecast after EE, before losses	GWh	1910	1905	1905	1911	1921	1935	1,940	1,947	1,956	1,965	1,974	1,981	1,990	1,998	2,007
% change in gross demand		-0.6%	-0.3%	0.0%	0.3%	0.5%	0.7%	0.3%	0.4%	0.4%	0.5%	0.5%	0.4%	0.4%	0.4%	0.4%

Elasticity	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Electricity rates (proxy to industrial rate)	$/MWh	$ 511	$ 570	$ 633	$ 670	$ 712	$ 750	$ 781	$ 807	$ 841	$ 870	$ 902	$ 935	$ 965	$ 998	$ 1,037
Real change in rate		8.81%	8.89%	8.51%	3.74%	4.06%	3.29%	2.08%	1.20%	2.24%	1.34%	1.65%	1.58%	1.23%	1.33%	1.85%
% difference of CHP vs rate of previous year	%	266%	302%	342%	388%	409%	432%	458%	471%	480%	501%	510%	521%	539%	547%	556%
Demand elasticity																
Implied change in demand		-7.0%	-6.9%	-6.9%	-6.7%	-3.0%	-3.2%	-2.6%	-1.7%	-1.0%	-1.8%	-1.1%	-1.3%	-1.3%	-1.0%	-1.1%
2019	GWh															
2020	GWh															
2021	GWh															
2022	GWh															
2023	GWh															
2024	GWh															
2025	GWh															
2026	GWh															
2027	GWh															
2028	GWh															
2029	GWh															
2030	GWh	(39)														
2031	GWh	(40)	(40)													
2032	GWh	(39)	(39)	(39)												
2033	GWh		(38)	(38)	(38)											
2034	GWh			(37)	(37)	(37)										
2035	GWh				(35)	(35)	(35)									
2036	GWh					(15)	(15)	(15)								
2037	GWh						(16)	(16)	(16)							
2038	GWh							(13)	(13)	(13)						
2039	GWh								(8)	(8)	(8)					
2040	GWh									(5)	(5)	(5)				
2041	GWh										(9)	(9)	(9)			
2042	GWh											(5)	(5)	(5)		
2043	GWh												(7)	(7)	(7)	
2044	GWh													(6)	(6)	(6)
2045	GWh														(5)	(5)
2046	GWh															(5)
Total	GWh	(118.4)	(117.3)	(113.9)	(109.5)	(87.2)	(66.6)	(45.0)	(38.1)	(26.5)	(22.2)	(19.2)	(21.0)	(18.4)	(18.0)	(16.8)

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PREPA Rate Forecast Model - Demand - Industrial (2) cont.

London Economics International LLC

Customer owned generation	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Solar LCOE (Shown in IRP)	*$/MWh*	$ 71	$ 70	$ 70	$ 69	$ 68	$ 68	$ 68	$ 68	$ 68	$ 68	$ 68	$ 68	$ 68	$ 68	$ 68
Solar (Utility-Scale) LCOE (Calculated)	*$/MWh*	$ 91	$ 91	$ 92	$ 92	$ 93	$ 93	$ 94	$ 94	$ 95	$ 96	$ 97	$ 98	$ 98	$ 99	$ 100
Wind (Utility-Scale) LCOE (Calculated)	*$/MWh*	$ 179	$ 182	$ 185	$ 188	$ 191	$ 194	$ 198	$ 202	$ 207	$ 211	$ 215	$ 220	$ 224	$ 229	$ 234
CCGT LCOE (Calculated)	*$/MWh*	$ 95	$ 97	$ 98	$ 100	$ 102	$ 104	$ 107	$ 109	$ 111	$ 114	$ 116	$ 119	$ 122	$ 124	$ 127
CHP	*$/MWh*	$ 125	$ 127	$ 129	$ 130	$ 132	$ 134	$ 134	$ 137	$ 139	$ 140	$ 143	$ 145	$ 146	$ 149	$ 152
Battery Storage LCOE (Calculated)	*$/MWh*	$ 83	$ 82	$ 80	$ 79	$ 78	$ 77	$ 76	$ 75	$ 74	$ 73	$ 73	$ 72	$ 71	$ 71	$ 70
Suitable LCOE for self-generation	*$/MWh*	$ 154	$ 152	$ 150	$ 148	$ 146	$ 145	$ 144	$ 143	$ 142	$ 141	$ 141	$ 140	$ 139	$ 139	$ 138
IRP forecasted self generation	*GWh*	-1944	-2031	-2122	-2221	-2315	-2417	0	0	0	0	0	0	0	0	0
IRP Incremental self generation		-81	-87	-91	-99	-94	-102	2417	0	0	0	0	0	0	0	0
Demand converted to self generation	*GWh*	(774)	(774)	(774)	(774)	(774)	(774)	(774)	(774)	(774)	(774)	(774)	(774)	(774)	(774)	(774)
Imcremental conversion	*GWh*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Conversion rate as % of demand in IRP		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Conversion threshold																
If rate is low, how much to discount conversion to DG																
Modeled conversion GWh		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Culmulative conversion to self-genreation		(762)	(762)	(762)	(762)	(762)	(762)	(762)	(762)	(762)	(762)	(762)	(762)	(762)	(762)	(762)
GDP from self-generation industries		$ 7,368	$ 7,339	$ 7,326	$ 7,289	$ 7,237	$ 7,171	$ 7,111	$ 7,074	$ 7,032	$ 6,989	$ 6,947	$ 6,908	$ 6,875	$ 6,841	$ 6,807

LEI demand forecast	unit	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Previous year's adjusted industrial GNP	*Real Millions US dollars*	$ 23,439	$ 22,937	$ 22,398	$ 21,978	$ 21,574	$ 21,247	$ 20,991	$ 20,724	$ 20,569	$ 20,453	$ 20,350	$ 20,258	$ 20,160	$ 20,090	$ 20,021
Current year industrial GNP due to economic dev	*Real Millions US dollars*	$ 23,333	$ 22,789	$ 22,356	$ 21,936	$ 21,533	$ 21,207	$ 20,869	$ 20,691	$ 20,537	$ 20,421	$ 20,318	$ 20,226	$ 20,148	$ 20,077	$ 20,008
Base demand from industrial activities	*GWh*	2,451	2,403	2,362	2,329	2,303	2,289	2,271	2,264	2,260	2,262	2,264	2,266	2,268	2,272	2,275
Demand not yet converted to self generation	*GWh*	1,689	1,641	1,600	1,567	1,541	1,527	1,509	1,502	1,498	1,500	1,502	1,504	1,506	1,510	1,513
Change in demand due to price elasticity	*GWh*	(118)	(117)	(114)	(110)	(87)	(67)	(45)	(38)	(26)	(22)	(19)	(21)	(18)	(18)	(17)
Non-self-gen demand after elasticity impact	*GWh*	1,571	1,524	1,486	1,458	1,454	1,460	1,464	1,464	1,472	1,477	1,483	1,483	1,488	1,492	1,496
Total industrial demand	*GWh*	2,333	2,286	2,248	2,220	2,216	2,222	2,226	2,226	2,234	2,239	2,245	2,245	2,250	2,254	2,258
Demand-GNP impact coefficient																
Industrial GNP impacted by demand change	*Real Millions US dollars*	$ (396)	$ (390)	$ (378)	$ (362)	$ (286)	$ (217)	$ (145)	$ (122)	$ (84)	$ (70)	$ (61)	$ (66)	$ (57)	$ (56)	$ (52)
Industrial GNP after demand impact	*Real Millions US dollars*	$ 22,937	$ 22,398	$ 21,978	$ 21,574	$ 21,247	$ 20,991	$ 20,724	$ 20,569	$ 20,453	$ 20,350	$ 20,258	$ 20,160	$ 20,090	$ 20,021	$ 19,957

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PREPA Rate Forecast Model - Demand - Agriculture

London Economics International LLC

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Agriculture (GWh)			26	26	26	26	27	27	27	27	27	26	26	26	26	26
Total Peak Demand (MW)			6	6	6	6	7	7	7	7	7	6	6	6	6	6
Load factor		*46.80%*														
Siemen's forecast after EE, before losses	*GWh*		*26*	*26*	*26*	*26*	*27*	*27*	*27*	*27*	*27*	*26*	*26*	*26*	*26*	*26*
Siemen's forecast before EE, before losses	*GWh*		*26*	*26*	*26*	*26*	*27*	*27*	*27*	*27*	*27*	*26*	*26*	*26*	*26*	*26*
Source	IRP page 56 and 57															
Agriculture as % of GDP	*%*	*0.8%*														
Government % of GDP	*%*	*12.2%*														
Non-govt agriculture as % of GDP	*%*	*0.7%*														
Agriculture GDP		400	422	428	424	425	426	428	424	421	418	414	412	410	408	406

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PREPA Rate Forecast Model - Demand - Agriculture cont.

London Economics International LLC

		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total Agriculture (GWh)		26	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Total Peak Demand (MW)		6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Load factor																
Siemen's forecast after EE, before losses	*GWh*	*26*	*25*	*25*	*25*	*25*	*25*	*25*	*25*	*25*	*25*	*25*	*25*	*25*	*25*	*25*
Siemen's forecast before EE, before losses	*GWh*	*26*	*25*	*25*	*25*	*25*	*25*	*25*	*25*	*25*	*25*	*25*	*25*	*25*	*25*	*25*
Agriculture as % of GDP	*%*															
Government % of GDP	*%*															
Non-govt agriculture as % of GDP	*%*															
Agriculture GDP		404	402	401	400	399	399	396	396	395	394	394	393	393	393	392

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PREPA Rate Forecast Model - Demand - Lighting

London Economics International LLC

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Lighting (GWh)		0	315	275	234	194	153	112	112	113	112	110	107	105	103	101
Total Lighting peak demand (MW)		-	73	64	54	45	35	26	26	26	26	25	25	24	24	23
Load factor		49.30%														
Siemen's forecast after EE, before losses	*GWh*		*315*	*316*	*317*	*318*	*320*	*320*	*321*	*321*	*320*	*319*	*316*	*313*	*311*	*309*
Siemen's forecast before EE, before losses	*GWh*		*315*	*275*	*234*	*194*	*153*	*112*	*112*	*113*	*112*	*110*	*107*	*105*	*103*	*101*
Source	IRP page 56 and 57															

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PREPA Rate Forecast Model - Demand - Lighting cont.

London Economics International LLC

		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total Lighting (GWh)		99	98	96	95	94	93	93	93	93	93	93	93	93	93	93
Total Lighting peak demand (MW)		23	23	22	22	22	22	22	22	22	22	22	22	22	22	22
Load factor																
Siemen's forecast after EE, before losses	*GWh*	*307*	*306*	*304*	*303*	*302*	*302*	*302*	*302*	*302*	*302*	*302*	*302*	*302*	*302*	*302*
Siemen's forecast before EE, before losses	*GWh*	*99*	*98*	*96*	*95*	*94*	*93*	*93*	*93*	*93*	*93*	*93*	*93*	*93*	*93*	*93*

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PREPA Rate Forecast Model - Demand - Others

London Economics International LLC

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total Others (GWh)		0	35.6	35.8	35.9	36	36.2	36.3	36.3	36.3	36.2	36.1	35.7	35.5	35.2	35
Total Others peak demand (MW)		-	6	6	6	6	6	6	6	6	6	6	6	6	5	5
Load factor		73.60%														
Siemen's forecast after EE, before losses	*GWh*		*35.6*	*35.8*	*35.9*	*36*	*36.2*	*36.3*	*36.3*	*36.3*	*36.2*	*36.1*	*35.7*	*35.5*	*35.2*	*35*
Siemen's forecast before EE, before losses	*GWh*		*35.6*	*35.8*	*35.9*	*36*	*36.2*	*36.3*	*36.3*	*36.3*	*36.2*	*36.1*	*35.7*	*35.5*	*35.2*	*35*
Source	IRP page 56 and 57															

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PREPA Rate Forecast Model - Demand - Others cont.

London Economics International LLC

		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total Others (GWh)		34.8	34.6	34.5	34.3	34.2	34.1	34.1	34.1	34.1	34.1	34.1	34.1	34.1	34.1	34.1
Total Others peak demand (MW)		5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Load factor																
Siemen's forecast after EE, before losses	*GWh*	*34.8*	*34.6*	*34.5*	*34.3*	*34.2*	*34.1*	*34.1*	*34.1*	*34.1*	*34.1*	*34.1*	*34.1*	*34.1*	*34.1*	*34.1*
Siemen's forecast before EE, before losses	*GWh*	*34.8*	*34.6*	*34.5*	*34.3*	*34.2*	*34.1*	*34.1*	*34.1*	*34.1*	*34.1*	*34.1*	*34.1*	*34.1*	*34.1*	*34.1*

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PREPA Rate Forecast Model - Demand elasticity

London Economics International LLC

	Study	Jurisdiction	Timeframe	Research year	Studied years	Residential	Commercial	Industrial	Total
1	Burke	US	Long Run	2017	2015	*-0.95*	*-0.34*	*-1.17*	*-0.88*
2	Burke	US	Short run	2017	2015	*-0.11*	*-0.05*	*-0.11*	
3	EPRI (low)	US	Long Run	2008	2001	*-0.70*	*-0.8*	*-0.9*	
4	EPRI (low)	US	Short Run	2008	2001	*-0.20*	*-0.2*	*-0.1*	
5	Paul, Myers and Palmer	US Pacific	Short run	2009		*-0.13*	*-0.17*	*-0.31*	
6	Paul, Myers and Palmer	US Pacific	Long Run	2009		*-0.37*	*-0.45*	*-0.81*	
7	Rand Corp	US	Short run	2005		*-0.2*	*-0.21*		
8	Rand Corp	US	Long Run	2005		*-0.32*	*-0.77*		

Long run	-0.32	-0.34	-0.81

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PREPA Rate Forecast Model - Self Generation assumptions

London Economics International LLC

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
New DG	GWh		62	183	249	300	350	404	456	514	575	642	708	781	857	941
New CHP	GWh		66	236	404	922	922	922	922	922	922	922	922	922	922	922
Total	GWh		128	419	653	1,222	1,272	1,326	1,378	1,436	1,497	1,564	1,630	1,703	1,779	1,863
Implied existing	GWh		59	16	179	49	122	105	105	105	105	105	105	105	105	105
Change in New DG				121	66	51	50	54	52	58	61	67	66	73	76	84
Change in New CHP				170	168	518	-	-	-	-	-	-	-	-	-	-
Total				291	234	569	50	54	52	58	61	67	66	73	76	84

Source IRP 2019

DG assumptions in CFP 2019		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Residential	GWh		72	158	184	210	236	262								
Commercial	GWh		100	238	304	347	372	395								
Industrial	GWh		15	39	344	714	786	774								
Total			187	435	832	1271	1394	1431								
Annual change				248	397	439	123	37								

Implied split		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Residential Solar	GWh		72	158	184	210	236	262	289	319	350	385	418	456	495	538
Commercial Solar	GWh		49	49	244	244	244	247	272	300	330	362	395	430	467	508
Commercial CHP	GWh		51	189	60	103	128	148	148	148	148	148	148	148	148	148
Industrial Solar	GWh		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Industrial CHP	GWh		15	39	344	714	786	774	774	774	774	774	774	774	774	774
Total			187	435	832	1271	1394	1431	1,483	1,541	1,602	1,669	1,735	1,808	1,884	1,968
CHP			66	228	404	817	914	922	922	922	922	922	922	922	922	922
Solar			121	207	428	454	480	509	561	619	680	747	813	886	962	1,046
Modeled				366	666	1,105	1,228	1,263	1,302	1,346	1,393	1,443	1,493	1,566	1,642	1,726

Key assumptions:
Residential will only build solar
Existing self-generation are all solar

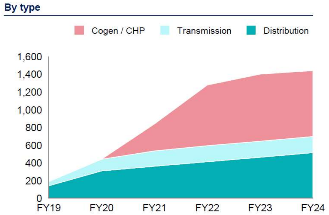
Excerpted from CFP2019 slide 61

Overview of Distributed Generation (DG) Assumptions

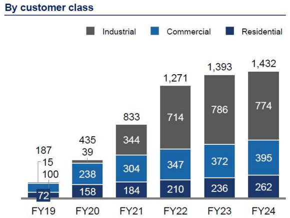
Based on analysis provided by Siemens in the IRP, the levelized cost of grid defection is higher than the cost of generation delivered to the customer, including the effect of losses until 2028 (when AES Coal retires). After 2028, grid defection cost is significantly lower than the total rate even before applying the non-bypassable transition charge component. This confirms the assumption in the DG forecast that the continuance of 'net-metering' rates will occur, and the customer side roof top PV adoptions will continue to be in line with the adoption rates observed to date.

Distributed Generation (GWh)

By type



By customer class



The Fiscal Plan assumes that DG will continue to rise due to customer perceptions on the need to control supply and the decreasing cost of DG technologies. As the transformation process advances, this trend is likely to continue, in parallel with distribution of the load, despite projected decreasing generation costs.

Source: 2019 Integrated Resource Plan - Appendix 4

61

Puerto Rico Electric Power Authority

Excerpted from IRP2019 Exhibit 3-18

Exhibit 3-18. Impact of Customer Owned Generation on the Energy Demand for Generation after EE

Fiscal Year	Total Energy Demand (GWh)	New Customer Owned Distributed Generation (GWh)	New CHP (GWh)	Total Energy Demand after DG & CHP (GWh)
2019	18,324	62	66	18,196
2020	17,829	183	236	17,410
2021	17,529	249	404	16,876
2022	17,251	300	922	16,028
2023	16,964	350	922	15,692
2024	16,659	404	922	15,333
2025	16,375	456	922	14,996
2026	16,066	514	922	14,630
2027	15,708	575	922	14,211
2028	15,320	642	922	13,755
2029	14,839	708	922	13,209
2030	14,390	781	922	12,687
2031	13,958	857	922	12,179
2032	13,533	941	922	11,670
2033	13,118	1,022	922	11,174
2034	12,713	1,109	922	10,682
2035	12,377	1,200	922	10,255
2036	12,052	1,298	922	9,831
2037	11,737	1,392	922	9,422
2038	11,429	1,494	922	9,012
CAGR	-2.45%	18.25%	14.86%	-3.63%

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PREPA Rate Forecast Model - Self Generation assumptions cont.

London Economics International LLC

		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
New DG	GWh	1,022	1,109	1,200	1,298	1,392	1,494	1,494	1,494	1,494	1,494	1,494	1,494	1,494	1,494	1,494
New CHP	GWh	922	922	922	922	922	922	922	922	922	922	922	922	922	922	922
Total	GWh	1,944	2,031	2,122	2,220	2,314	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416	2,416
Implied existing	GWh	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105
Change in New DG		81	87	91	98	94	102	-	-	-	-	-	-	-	-	-
Change in New CHP		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total		81	87	91	98	94	102	-	-	-	-	-	-	-	-	-
Source	IRP 2019															

DG assumptions in CFP 2019		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Residential	GWh															
Commercial	GWh															
Industrial	GWh															
Total																
Annual change																

Implied split		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Residential Solar	GWh	580	625	672	722	771	823	823	823	823	823	823	823	823	823	823
Commercial Solar	GWh	547	589	633	681	726	776	776	776	776	776	776	776	776	776	776
Commercial CHP	GWh	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148
Industrial Solar	GWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Industrial CHP	GWh	774	774	774	774	774	774	774	774	774	774	774	774	774	774	774
Total		2,049	2,136	2,227	2,325	2,419	2,521	2,521	2,521	2,521	2,521	2,521	2,521	2,521	2,521	2,521
CHP		922	922	922	922	922	922	922	922	922	922	922	922	922	922	922
Solar		1,127	1,214	1,305	1,403	1,497	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599	1,599
Modeled		1,807	1,894	1,985	2,083	2,177	2,279	2,279	2,279	2,279	2,279	2,279	2,279	2,279	2,279	2,279

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PREPA Rate Forecast Model - WACC assumptions

London Economics International LLC

	T&D WACC	Sources and notes	Sources
Rate of Debt	8.67%		
Tax rate	25.00%	U S federal corporate income tax rate of 21 percent, with 4% buffer	https://www irs gov/forms-pubs/2017-fiscal-tax-year-filers-must-use-blended-corporate-tax-rates
Cost of Equity	12.70%	Average authorized RoE for select Islands (Dominica, Jamaica, Barbados)	https://fred stlouisfed org/series/BAMLEMRLCRPILAEY#0
Risk Premium	3.35%	Damodaran - Average Country risk premium for Caribbean, south and central America	http://pages stern nyu edu/~adamodar/New_Home_Page/datafile/ctryprem html
Adjusted Cost of Equity	16 05%		
Cost of Debt	6 50%		
Percent Equity	45.00%	In the last 3 years, the average utility debt/equity ratio was approximately 1 23, which translates to 55/45 debt/equity ratio	https://www epa gov/sites/production/files/2015-08/documents/chapter_8_financial_assumptions pdf
Percent Debt	55 00%		
WACC	10 80%		

	IPP WACC	
Rate of Debt	9.51%	Based on average bond yield for AES Corp stock due in may 15, 2023, March 15 2024, and Apr 15, 2025
Tax rate	25 00%	
Adjusted Cost of Equity	26.19%	Invesco S&P 500 equal weight utilities ETF
Cost of Debt	7 13%	
Percent Equity	30.00%	Average debt/ equity from EPA merchant generators capital structures for base case
Percent Debt	70 00%	
WACC	12 85%	

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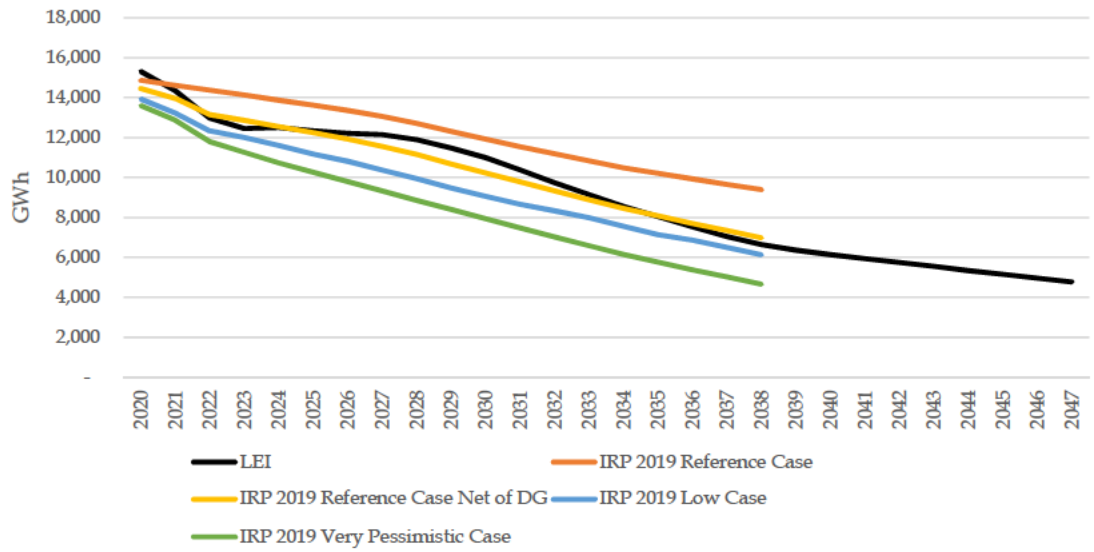
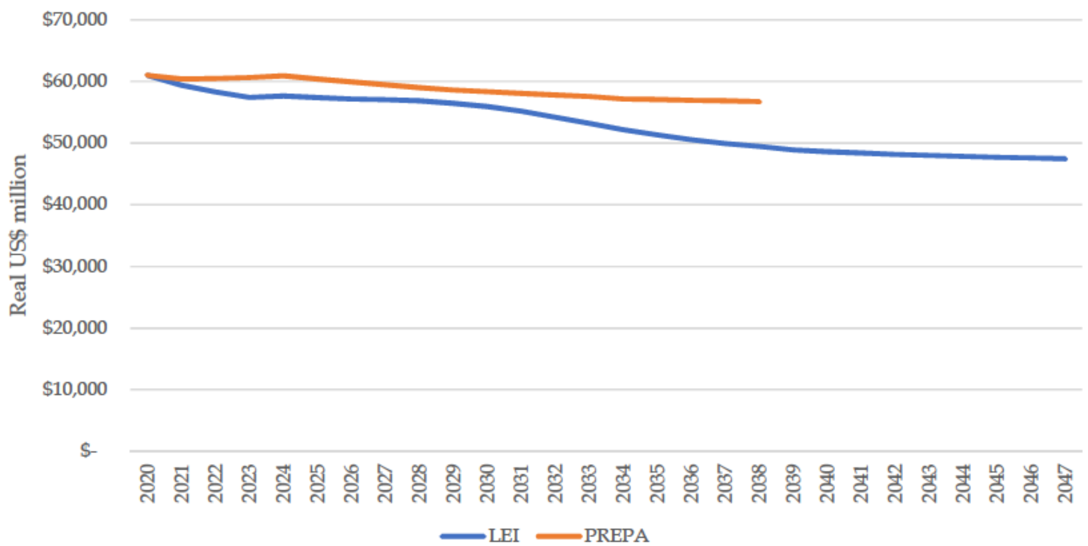
PREPA Rate Forecast Model - Graph 1

London Economics International LLC

Forecasted PREPA billable demand



Forecasted GNP



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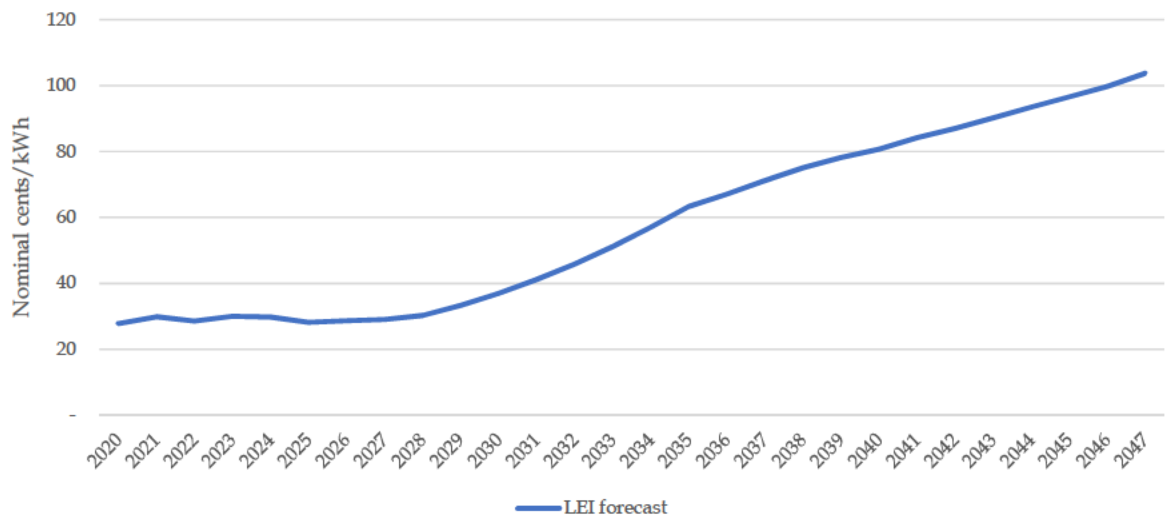
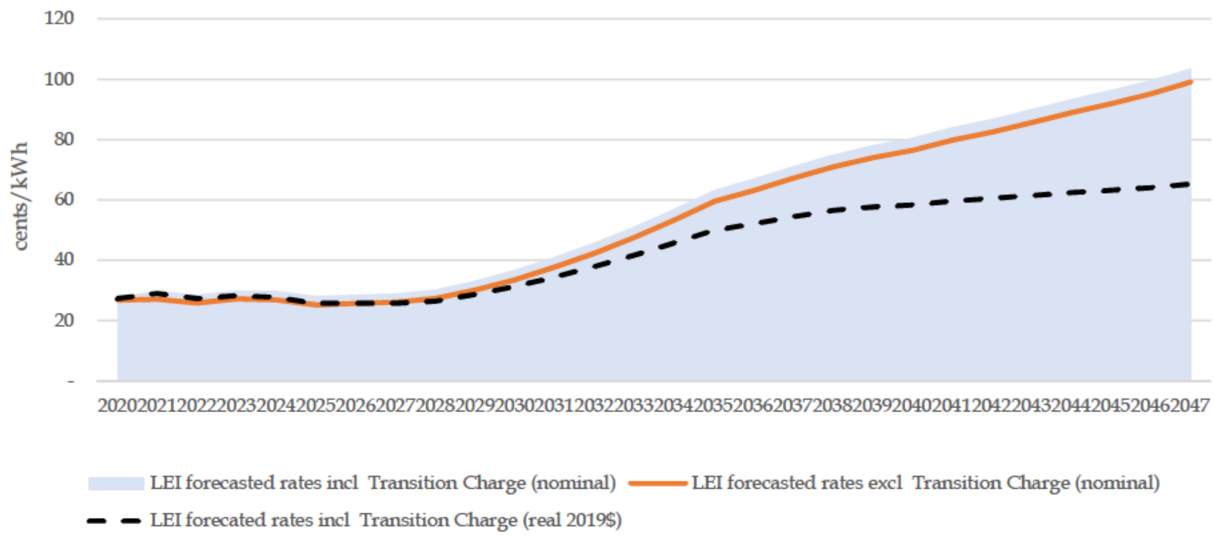
PREPA Rate Forecast Model - Graph 2

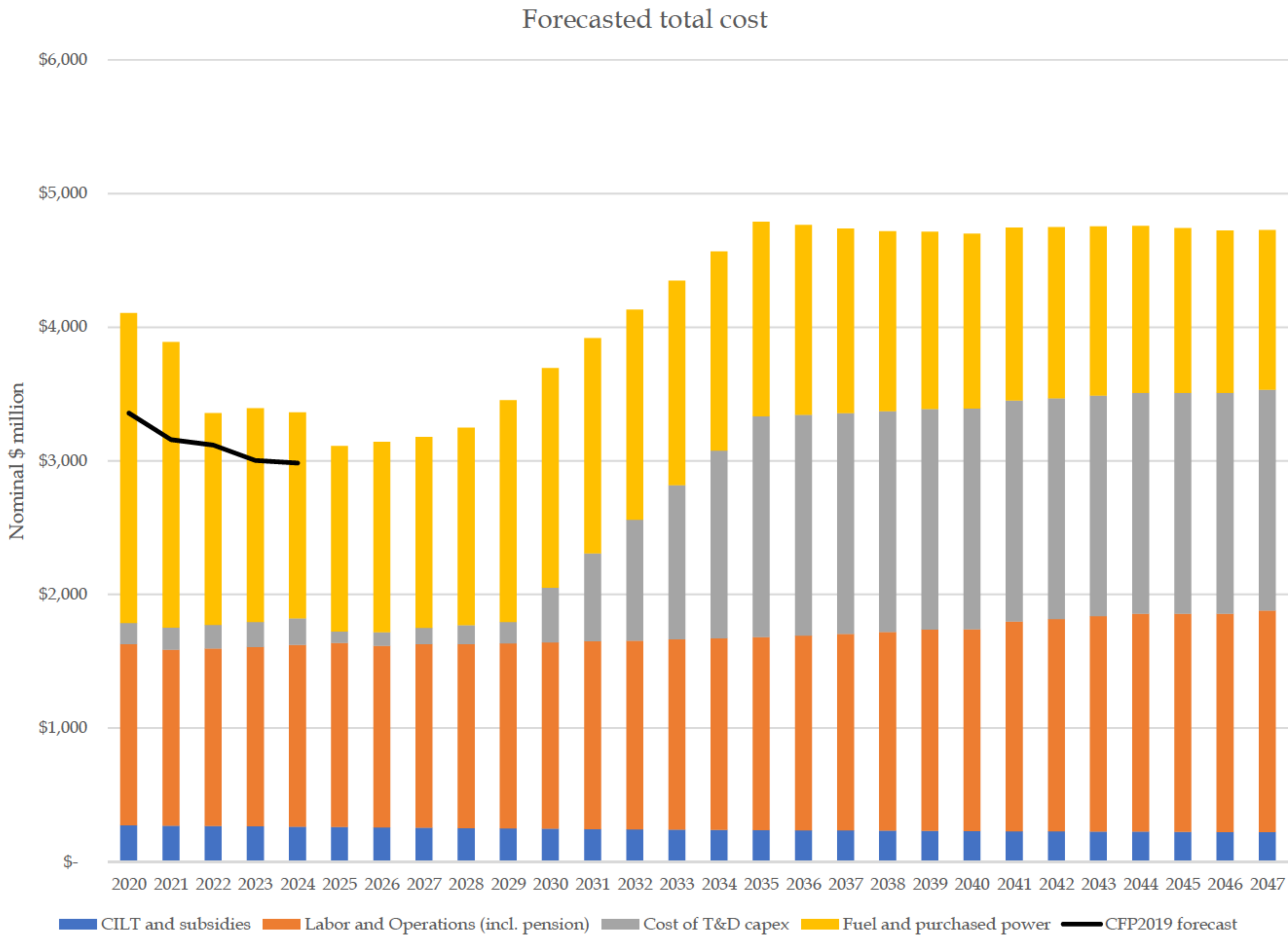
London Economics International LLC

Forecasted PREPA rates (nominal cents/kWh)



Transition charge impact analysis




Forecasted total cost
$6,000
$5,000
$4,000
$3,000
$2,000
$1,000
$-
Nominal $ million
2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047
CILT and subsidies
Labor and Operations (incl. pension)
Cost of T&D capex
Fuel and purchased power
CFP2019 forecast

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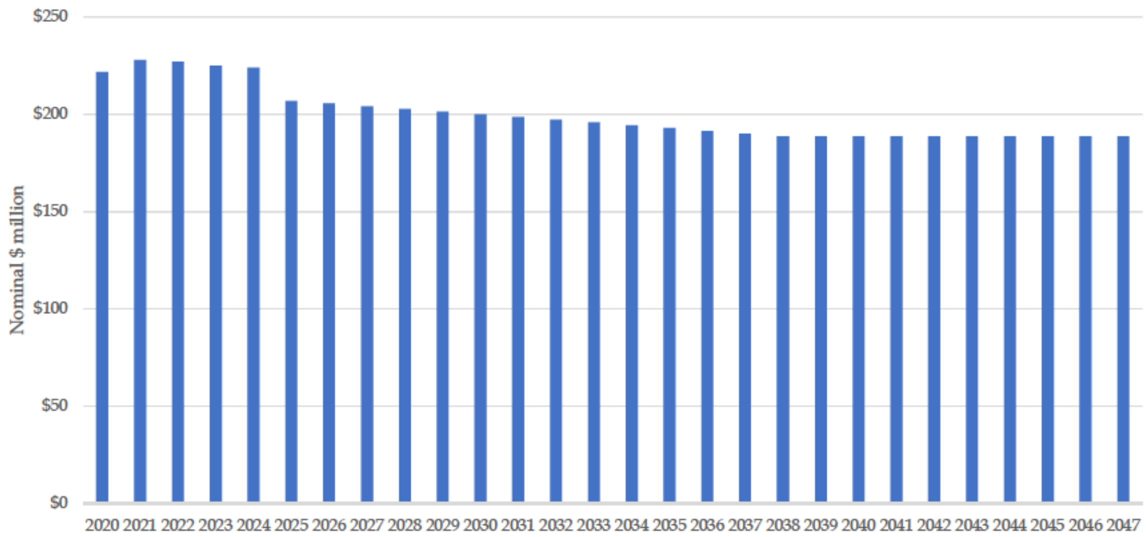
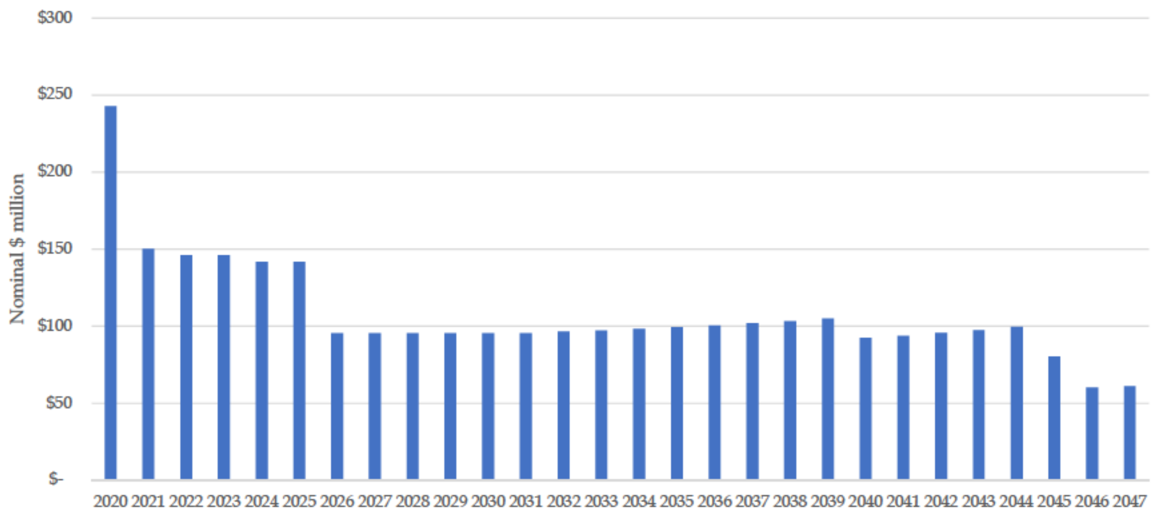
PREPA Rate Forecast Model - Graph 3

London Economics International LLC

Forecasted pension cost



Forecasted O&M costs for Generation



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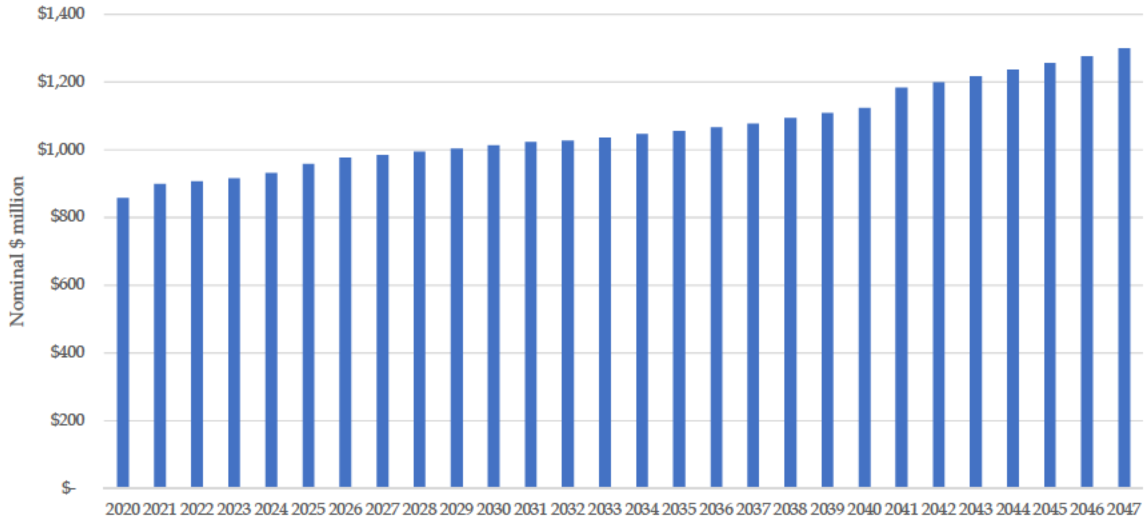
PREPA Rate Forecast Model - Graph 4

London Economics International LLC

Forecasted O&M costs for T&D



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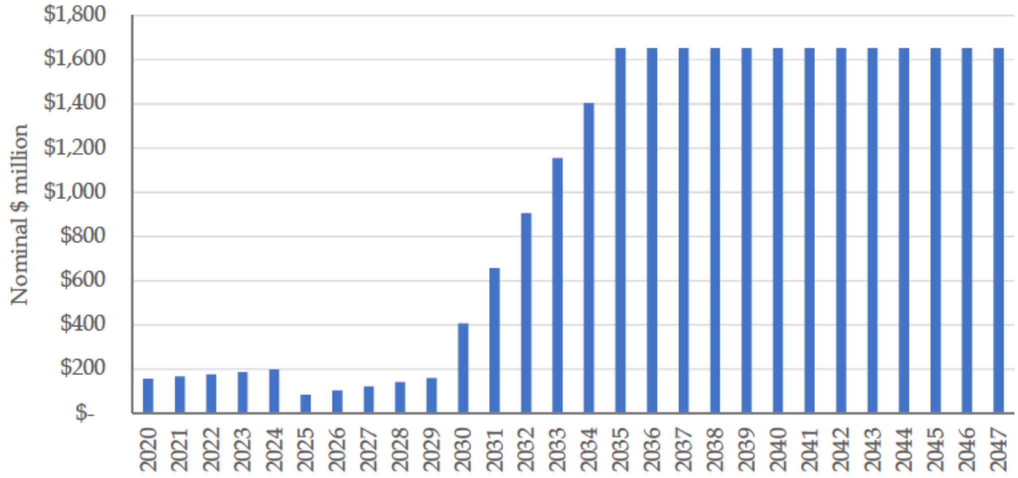
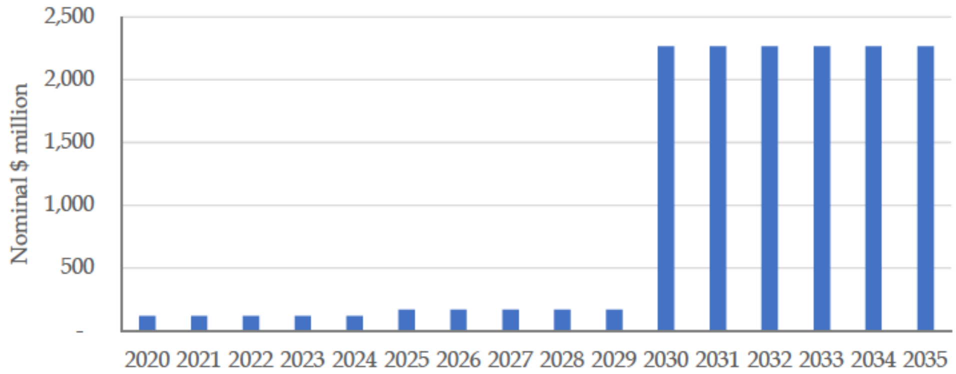
PREPA Rate Forecast Model - Graph 5

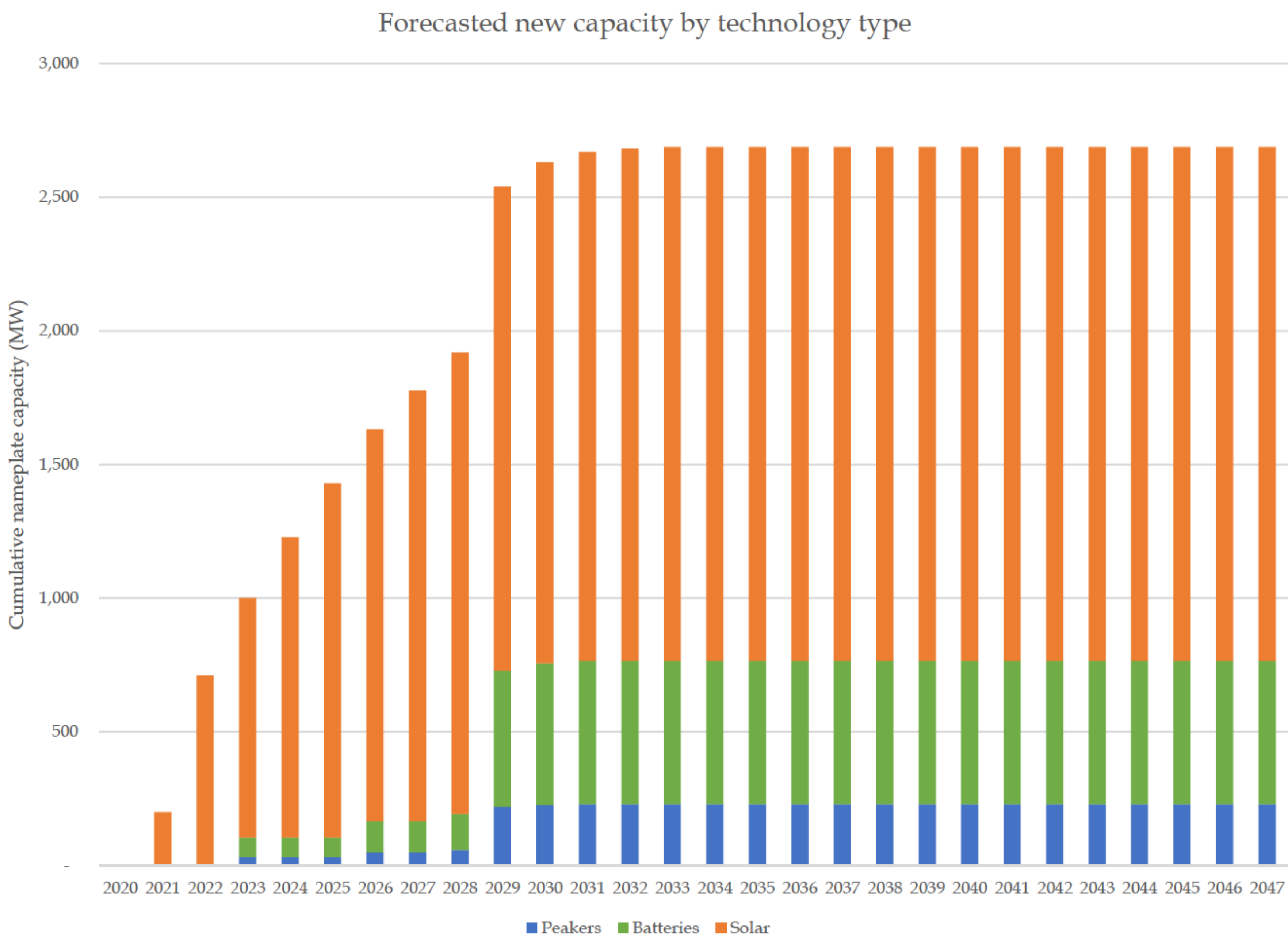
London Economics International LLC

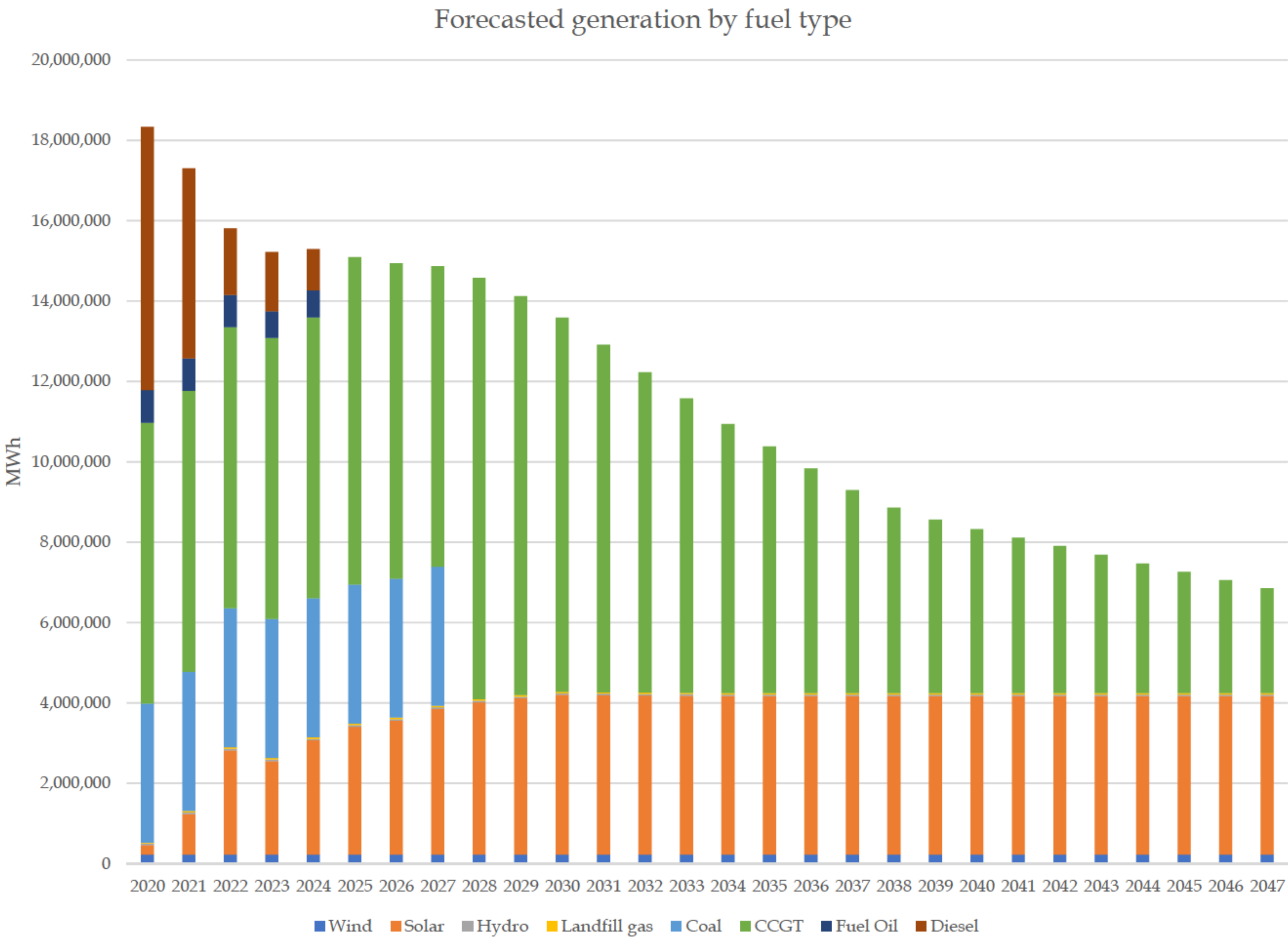
Forecasted T&D capex



Forecasted T&D Investment budget forecast




Forecasted new capacity by technology type
Cumulative nameplate capacity (MW)
3,000
2,500
2,000
1,500
1,000
500
-
2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047
Peakers Batteries Solar


Forecasted generation by fuel type
MWh
20,000,000
18,000,000
16,000,000
14,000,000
12,000,000
10,000,000
8,000,000
6,000,000
4,000,000
2,000,000
0
2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047
Wind
Solar
Hydro
Landfill gas
Coal
CCGT
Fuel Oil
Diesel

Exhibits to

Critique of Government Parties' Assertions that the 9019 Settlement Will Not Affect Non-settling Creditors and Will Avoid a Subsequent Title III Filing by PREPA

prepared for the Official Committee of Unsecured Creditors of the Puerto Rico Electric Power Authority

Exhibit A: CV for Julia Frayer

Exhibit B: Qualifications for London Economics International LLC

LONDON ECONOMICS

London Economics International LLC
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Boston, MA 021111
Tel: (617) 933-7200
Fax: (617) 933-7201
www.londoneconomics.com

1 Exhibit A: Curriculum Vitae for Julia Frayer

KEY QUALIFICATIONS:

Julia Frayer is a Managing Director with London Economics International LLC ("LEI"), specializing in economic analysis and evaluation of infrastructure assets, such as power plants, natural gas-related infrastructure, electricity transmission and distribution systems, and utilities, as well as market design and expert economic advisory services for regulated and competitive power markets. She has worked extensively in the US, Canada, Europe, and Asia in valuing electricity generation and wires assets, water and wastewater networks, as well as gas transportation assets. She also provides expert advice on market rules, innovative rate design, and institutional best practices for management of infrastructure assets.

Julia manages LEI's quantitative financial and business practice area, and also specializes in market and organizational design issues related to electricity. In addition to electric generation sector market power and anti-trust analysis, sample projects include cost of capital estimation; rate-setting analysis; short- and long-term forecasting of wholesale power prices; valuation of generators and vertically-integrated utilities; assessment of retail market design including provider-of-last resort portfolios and contracts; design of energy sales agreements; and advisory on structuring request for proposals and sale processes for energy assets and derivative contracts. As part of these analyses, Julia and her team of economists and consultants have developed and applied proprietary real-options based valuation tools, portfolio risk analytics, models of strategic bidding behavior, and sophisticated power system simulation tools, as well as customized econometric models. Julia also leads many of the firm's regulatory economics projects, spanning such diverse issues as cost-benefit analysis, market power mitigation, tariff ratemaking, auction design (including competitive solicitations for procurement), wholesale market rules design, productivity analysis and efficiency benchmarking.

Prior to joining LEI, Julia was working as an Investment Banker with Merrill Lynch in New York.

EDUCATION:

Boston University, Boston, Massachusetts, B.A. in Economics and International Affairs.

Boston University, Boston, Massachusetts, M.A. in Economics.

EMPLOYMENT RECORD:

From: 1998	**To:** present
Employer:	*London Economics International LLC, United States* Managing Director

SAMPLE OF PROJECT EXPERIENCE:

The projects briefly described below are typical of the work Julia has performed throughout her career at London Economics International.

Written and Oral Testimony (listed in chronological order)

- ***expert witness for a performance-based ratemaking assignment:*** LEI was retained in early 2019 to provide expert technical advice and analysis to a gas utility company in Massachusetts, in anticipation of a performance-based distribution ratemaking application that will be submitted to their state regulator in the fourth quarter of 2019.
- ***provided independent assessment of Alberta's Comprehensive Market Design:*** LEI provided a critical review of the new capacity and energy market design being proposed by the Alberta Electricity System Operator ("AESO") in a written report submitted, on behalf of a market participant, to the Alberta Utilities Commission ("AUC"). LEI identified criteria for evaluation of the new market design, compared the AESO's proposal against other well-established organized wholesale electricity markets, and then categorized associated rules based on an objective evaluation of both positive and negative features. Julia Frayer testified before the AUC in June 2019. The new provincial government suspended the proceeding in July 2019, before the regulator was able to issue a decision. [AUC Proceeding No. 23757]
- ***assessment of Efficiency Maine Trust's submission of its program plan and specifically the avoided cost of energy supply:*** LEI was retained by the Maine Public Utility Commission ("MPUC") to provide an independent forecast of future natural gas prices, wholesale energy and capacity prices, which would be relevant for cost effectiveness analysis of future energy efficiency programs. LEI was also asked to review the multi-stakeholder report that Efficiency Maine Trust and other New England program administrators commissioned in 2014 (and 2015 Update), and subsequently in 2017. LEI staff testified before the MPUC on several occasions over the course of this multi-year engagement. [MPUC Docket 2018-00321]
- ***evaluation of the efficacy of distributed generation as a non-transmission solution to local transmission reliability problems:*** LEI prepared direct testimony and rebuttal testimony related to the technical efficacy and cost-effectiveness of various non-transmission alternatives and specifically distribution levels solar and battery storage solution to a known reliability problem in a load pocket within Massachusetts. [Massachusetts, EFSB 17-02/D.P.U. 17-82/17-83]
- ***independent evaluation of New England Clean Energy Connect transmission project in its siting proceeding at the Maine Public Utility Commission ("MPUC"):*** LEI was retained in 2017 to advise the MPUC staff on the wholesale electricity market impacts and macroeconomic effects of the new transmission project on Maine's economy and the economies of other New England states. LEI prepared an independent forecast of future energy and capacity market benefits, carbon emissions reductions, and local GDP and employment impacts as a result of the construction and operations of the project; LEI also critically reviewed the submission of other parties on this topic. After providing written testimony, LEI staff led by Julia Frayer testified at the MPUC in late 2018. [MPUC Docket 2017—00232]

- ***conducted non-transmission alternative study:*** LEI was hired to conduct a Non-Transmission Alternatives ("NTA") analysis for the two transmission projects, which are a component of larger transmission solution being proposed by Eversource for the Greater Hartford and Central Connecticut ("GHCC") area. The objective of the NTA analysis was to determine the feasibility and viability of other non-transmission resources – such as new generation and new demand-side resources – to be developed in lieu of these two specific transmission projects to relieve transmission reliability concerns. The NTA analysis was filed as part of Eversource's application with the Connecticut Siting Council ("CSC") for each of these transmission projects. [CSC Docket No. 474]
- ***served as Independent Examiner for Western Interconnect transmission line:*** LEI was selected by developers of the Western Interconnect transmission line in New Mexico to serve as Independent Examiner for their Open Season process, through which WI offered transmission capacity over the line to any interested party at the same rates, terms and conditions as those offered to anchor customers on the line. LEI designed and managed the entire process, which included creating the evaluation criteria, drafting announcements and press releases, preparing the Open Season documents and forms, conducting information sessions, overseeing the process website, and evaluating and ranking bids. At the conclusion of the process, LEI prepared and submitted a report to FERC (in docket ER15-2647) attesting that the process was market-driven, fair, transparent, and non-discriminatory. [FERC Docket No. ER15 – 2647]
- ***independent evaluation of the costs and benefits of the Northern Pass transmission project:*** LEI submitted written testimony to the Site Evaluation Committee ("SEC") in New Hampshire on the costs and benefits of the proposed transmission project; the analysis focused on wholesale electricity market impacts as well as macroeconomic effects of lower electricity rates and infrastructure investment at the state level in New Hampshire and other states in the region; Julia Frayer also provided oral testimony as part of the SEC's hearings on the project. [SEC Docket No. 2015-06]
- ***engaged by Eversource and National Grid to determine the economic viability of non-transmission alternatives ("NTAs")***: LEI started the analysis by screening prospective NTA technologies based on their technical characteristics, their relevance in the New England market and their technical applicability. LEI conducted a comparative cost analysis to estimate the levelized cost per kW-month over the economic life of each of the technologies. Finally, the most probable combinations of NTA technologies identified in the selection process were further evaluated based on criteria including physical constraints such as land availability, siting issue, financing hurdle, etc. This NTA analysis was conducted for three separate NTA projects that together formed a part of the overall Greater Boston Reliability Project (also known as "AC Solution"). LEI also provided oral testimony about its analysis to the Massachusetts regulator for each of these projects: Wakefield-Woburn NTA Analysis (DPU 15-140 & 15-141), Mystic-Woburn NTA Analysis (DPU 15-64 & 15-65) and Merrimack Valley Reliability Project (DPU 15-44 & 15-45).
- ***estimation of the spot market and forward market impacts around the discretionary timing of outages by large generation owner in Alberta:*** LEI prepared an independent analysis of the spot market and forward market impacts of outage scheduling practices by TransAlta

over the period of 2010-2011; the analysis was filed with the Alberta Utilities Commission ("AUC") as part of a litigated case of alleged market power abuse. [AUC Proceeding No. 3110]

- ***testified on behalf of the NEPOOL in a jump ball filing at FERC regarding the Performance Incentive scheme proposed by ISO-NE:*** in written testimony submitted to FERC on behalf of NEPOOL, Julia Frayer identified shortcoming in ISO-NE's proposed performance incentive scheme for its forward capacity market. [Docket No. ER14-1050 at FERC]
- ***assisted in exploring options to expand Maine's natural gas supply:*** LEI was engaged by the State of Maine Public Utilities Commission ("MPUC") to assist it in evaluating options for expansion of natural gas supply into Maine (with a view to reducing the cost of gas and power to Maine customers). LEI reviewed and evaluated proposals for firm natural gas transportation service by pipeline developers. These evaluations included LEI's review of commercial terms include in the pipeline Precedent Agreements that underpin capacity expansion projects; review of contract provisions for Firm Transportation Agreements and Negotiated Rate Agreements; and evaluation of the status of the FERC and state-level permitting process for each pipeline proposal. The project also included natural gas network modeling (using GPCM, an industry-standard network model of the North American natural gas system) and power simulation modeling (using LEI's proprietary POOLMod model) to arrive at a quantitative cost-benefit analysis of proposals. LEI also conducted a Regional Analysis to assess the impact on Maine if it were to go forward under a regional initiative to procure pipeline capacity. Testimony was filed in February 2016 and LEI testified in March 2016. [MPUC Docket Number 2014-00071]
- ***provided an analysis of building block incentive ratemaking approaches and their applicability to Enbridge, a natural gas distribution utility in Ontario:*** LEI's report supported the client's distribution tariff proposal submission to the Ontario Energy Board ("OEB") for a second-generation Customized Incentive Regulation ("IR") plan for the period of five years (2014-2018). The testimony set out the theory behind as well as the practical experience of using the building blocks approach in incentive regulation regimes. Julia Frayer appeared before the OEB for cross examination. [OEB Docket No. EB-2012-0459]
- ***merger analysis between hydroelectric operators:*** Julia and her team of economists supported the client in preparation of a merger application to the Federal Energy Regulatory Commission ("FERC") under Section 203 of the Federal Power Act, in conjunction with the client's acquisition of a Maine-based hydroelectric generation portfolio. LEI performed a full Delivered Price Test analysis for the ISO New England control area. LEI's analysis was filed with FERC and the Merger Application was approved in early 2013; market-based rate authority was subsequently granted in mid 2013. [FERC Docket No. ER13-1613]
- ***assessment of congestion in the New York power market:*** LEI was commissioned by a coalition of community groups to prepare an independent outlook of the New York power wholesale market conditions and assess the level of congestion anticipated on major transmission interfaces within the state. LEI studied multiple scenarios to illustrate the impact of major drivers on congestion levels. LEI presented the findings at a technical conference organized by the New York Public Service Commission ("NYPSC") for the purpose of evaluating the benefits of new AC transmission projects. [NYPSC Case 12-T-0502]

- ***merger analysis in support of the NRG, Inc. and GenOn merger:*** LEI staff, under Julia's direction and guidance, performed Delivered Price Tests analysis for the Federal Energy Regulatory Commission ("FERC") under Section 203 of the Federal Power Act and submitted extensive analysis to FERC in the summer of 2012. The Merger Application was successfully approved by FERC in December 2012. Subsequently, LEI assisted the client in preparation of the 205 market-based rate authority analysis. [FERC Docket No. EC12-134]
- ***prepared testimony and testified in support of TransAlta in relation to a settlement for contravention of FEOC Regulation related to timing of exports from 2010:*** The settlement was crafted by the Market Surveillance Administrator and filed with the Alberta Utilities Commission ("AUC") for approval in December 2011. LEI assessed the economic and policy considerations of the settlement and its appropriateness in context of enforcement and sufficiency of penalty payment. [AUC Proceeding No. 1553]
- ***served as testifying witness on the issue of utility joining a wholesale market:*** Julia served as a testifying witness and lead author in evaluating Entergy's decision to join the Midwest Independent Transmission System Operator ("MISO") Regional Transmission Organization ("RTO") on the behalf of the Public Utility Commission of Texas. LEI evaluated several existing cost/benefit studies related to Entergy's decision to join MISO over the Southwest Power Pool ("SPP") and provided quantitative and qualitative analysis of specific costs/benefits attributable to ETI and its customers following membership in either MISO or SPP, including but not limited to net trade benefits, transmission cost allocation, governance issues, and continued participation in the Entergy Service Agreement following RTO membership. [SOAH Docket No. 473-12-6206; PUCT Docket No. 40346]
- ***prepared total factor productivity study and presented testimony in respect of Ontario Power Generation's ("OPG") hydroelectric incentive ratemaking plan:*** LEI was retained by OPG to assist in the development of its first generation IRM plan, following the formulaic I-X approach. LEI prepared an industry study of TFP trends spanning the North American hydroelectric sector. LEI also recommended an inflation index, which reflected cost drivers relevant to OPG while also aligning with the regulatory precedent in Ontario. LEI testified before the Ontario Energy Board. LEI's analysis supported the successful approval of OPG's first generation IRM plan for its regulated hydroelectric fleet. [OEB Docket No. EB 2012-0340]
- ***provided testimony regarding proposed merger of two regional utilities at PURA:*** Julia provided written testimony and oral testimony at the Connecticut Public Utility Regulatory Authority ("PURA") related to the market power consequences of proposed merger of NU-NSTAR. [PURA Docket No. 12-01-07]
- ***served as Independent Expert regarding Load Following Service products:*** ENMAX retained LEI to act as an independent expert on matters related to proposed auctioning for the Load Following Service ("LFS") product. LEI provided an independent evaluation of the proposed auction, including evaluation of the both the product being auctioned and the auction mechanism and key parameters. The LFS product as proposed to be auctioned was meant to represent the "shape risk" in the RRO service. LEI's evaluation considered whether the product and auction mechanism would result in an efficient, competitive and fair outcome for the Alberta market, RRO providers, potential suppliers of the auctioned product, and customers of the RRO service. LEI prepared a report titled "Independent assessment of

proposed market-based determination of shape risk in RRO supply" dated January 24, 2014, which was filed in ENMAX's Application No. 1610120 before the Alberta Utilities Commission ("AUC"). [AUC Proceeding No. 2941]

- ***testimony in support of transmission operating rules and curtailment protocols for interties into Alberta:*** Julia provided testimony in support of transmission operating rules and curtailment protocols for interties into Alberta, as proposed by the Alberta Electricity System Operator ("AESO"), in order to support a fair, efficient and openly competitive power market. The testimony was made in front of the Alberta Utilities Commission ("AUC"), on behalf of Morgan Stanley Capital Group ("MSCG"), a customer of the Montana-Alberta Transmission Line. Julia's analysis considered commercial as well as operating protocols in deregulated power markets and how market rules incentivize new entry and produce dynamic efficiency gains related to more intense competition The AUC issued a favorable decision to MSCG in early 2013. [AUC Proceeding No. 1633]

- ***conducted RPS review:*** Pursuant to *An Act To Reduce Energy Prices for Maine Consumers*, P.L 2011, ch.413, sec. 6 (the "Act") , the Maine Public Utilities Commission ("MPUC") was directed by the Legislature to study Maine's renewable portfolio requirement established in 35-A M.R.S.A. § 3210 (3-A). LEI was engaged by MPUC to conduct an in-depth analysis of the renewable portfolio standards ("RPS") required by the Act which would support the MPUC's study and report to the Legislature. Julia led the team in preparation of the report, which was submitted to the Commission in January 2012 and later testified at the state legislature on the key findings of that report. [MPUC Docket No. 2011-271]

- ***prepared detailed cost-benefit analysis and macroeconomic impact analysis in support of the Champlain Hudson Power Express ("CHPE") application for siting approval at the New York Public Service Commission ("NYPSC"):*** LEI's analysis on economic effects was the cornerstone of the settlement agreement reached between Transmission Developers Inc. and a number of New York agencies. Julia acted as the independent expert on behalf of TDI and prepared updated study results on energy market impacts, capacity market impacts and also macroeconomic benefits stemming from the operation of the CHPE project. Julia's testimony was used in the NYPSC proceeding in the summer of 2012 and CHPE was successfully granted its Article VII permit. [NYPSC Case 10-T-0149]

- ***served as lead expert witness for a private equity investor in matter related to a contractual dispute regarding a long term power purchase agreement between a municipal utility located in New England and a landfill gas generator:*** Ms. Frayer analyzed key contractual terms of the PPA and provided an expert's review of how those terms compared to the industry norm when the contract was signed and became effective. Ms. Frayer provided an independent estimate of potential contractual damages. The case was scheduled to be heard in Massachusetts Superior Court, however, Julia's analysis helped support a successful settlement. [Commonwealth of Massachusetts Superior Court Department, Civil Action No. PLCV2006-00651-B]

- ***provided expert testimony in support of FortisAlberta Inc. ("FAI") in its filing for a performance-based ratemaking ("PBR") plan with the Alberta Utilities Commission ("AUC"):*** The testimony provided detailed data analysis (including inflation and Total Factor Productivity trends), underpinning PBR economic theory, and reviews of best practices in

various North American and International jurisdictions. The testimony offers back up elements for each of the various components of the PBR plan that is being proposed by FAI. Julia testified at the AUC in Spring of 2012. [AUC Proceeding No. 566]

- ***provided testimony on behalf of NRG Energy, Inc. in opposition to the proposed acquisition of NRG by Exelon Corp (Exelon):*** LEI performed a preliminary Herfindahl-Hirschman Index test for market power for all regions affected, and a Delivered Price Test, for various parts of the PJM market (including PJM East and Western PJM). In addition, LEI examined Exelon's post-merger optimal bidding strategies using our proprietary model of strategic, known as CUSTOMBid. LEI also assessed the impact of changes in the parent company Exelon's cost of capital on the activities of the company's two regulated subsidiaries: Commonwealth Edison and PECO. LEI also estimated the impact on customer costs from potential debt downgrades following the merger and assessed the effectiveness of Exelon's proposed ring-fencing measures. LEI's written evidence was filed with FERC and Pennsylvania Public Utility commission. [PaPUC, Docket Nos. A-2009-2093057, A-2009-2093058 and A-2009-2093059]
- ***testimony at FERC on market power issues on behalf of intervener in proposed Exelon-PSEG merger per Section 203 of the Federal Power Act:*** In May 2005, Julia provided direct and supplemental testimony outlining key considerations relating to the potential for adverse competitive effects in light of the proposed merger and recommended additional mitigation measures to cure horizontal market power concerns through independent analysis of merger's impact on wholesale energy and capacity markets in PJM. [FERC Docket No. EC09-32]
- ***provided expert testimony before FERC related to Shell Energy's sale of capacity commitments from facilities in New York to New England in an alleged market manipulation case:*** Julia examined market rules, operating procedures, and pricing arrangements in New England and New York at the time of the investigation, and examined the participation of Shell in the capacity markets and compliance offers in the energy markets, commenting on the economic rationale behind the client's must offer strategies in the energy market for capacity compliance. [FERC Docket No. EL-09-47 and EL-09-48]
- ***prepared testimony on cost-benefit analysis of M&A transaction:*** Julia submitted testimony on behalf of the Staff of the Maryland Public Service Commission ("MPSC") to the MPSC to conduct a cost-benefit analysis in relation to the proposed transaction between Constellation Energy Group, Inc. ("CEG") and Électricité de France ("EDF") whereby EDF would purchase from CEG a 49.99% interest in Constellation Energy Nuclear Group, LLC ("CENG"). Benefits related to the decreased likelihood of a Baltimore Gas & Electric ("BGE") downgrade, increased likelihood of the Calvert Cliffs expansion being completed and several macroeconomic benefits stipulated to by EDF. Costs related to the limitation on the allocation costs of CEG corporate support services to CENG, increased risk of capital deprivation and reduced quality of service, and implications of CEG's more aggressive nuclear development. [MPSC, Case No. 9173]
- ***assessed the costs and benefits of new transmission versus generation alternatives to the system:*** LEI analyzed New England wholesale electricity markets to determine whether the Greater Springfield Reliability Project ("GSRP") would produce economic benefits to the New England region. In order to ensure that economic benefits were not subject to the forced

outage and availability schedule of the simulated energy markets, LEI simulated the energy market with 30 different random forced outage and availability schedules. Using these simulations, a distribution of results was used to calculate confidence intervals and hypothesis tests run on the results, hence increasing the robustness of our findings. The study results were used to produce written testimony to the Connecticut Siting Council ("CSC") and oral testimony was provided in late August and early September 2009. [CSC Docket No. 370B]

- ***served as Independent Monitor in a multi-state renewables solicitation process:*** Julia was part of a consortium that served as the Independent Monitor for PacifiCorp's renewable solicitation process for the 2008R-1 solicitation process for additional renewable power supplies. The Independent Monitor reported to the Utah Public Service Commission ("Utah PSC"), but filings were also made with the Oregon regulator. This process included review and assessment of the solicitation process, documents, and modeling methodologies; valuation of the bidder pre-approved process; development of review criteria, monitoring, auditing, and validation of bid evaluation process; bid evaluation; contract negotiation. [Docket No. UM1368]
- ***advised the Coalition of Large Distributors in Ontario on 3rd generation Incentive Regulation Mechanism proceedings of the Ontario Energy Board:*** The work involved expert testimony filed with the Board with detailed analysis of the theory behind the various components of PBR system, including inflation and efficiency gains factors, treatment of capital expenditures among others. The analysis was supplemented with comparison of actual factors and indices, and determination of the more robust and appropriate indices for the Ontario's distribution industry, including total factor productivity analysis for the sector. [OEB Docket No. EB-2007-0683]
- ***prepared proposal on pricing safeguards:*** In September 2005, Julia's proposal for pricing safeguards in the wholesale market, referred to as the Peaker Entry Test, was submitted to the Public Utility Commission of Texas ("PUCT") as an alternate to the Commission staff's proposal initially under Project No. 24255 which was later moved to and renamed by the PUCT Project No. 31972. In April 2006, the PUCT adopted a variant of this proposal for use as pricing safeguards – the Scarcity Pricing mechanism. Under Project No. 29042 in September 2005 Julia looked at the Pivotal Supplier Test and supplied a critique of the PUCT staff's initial market power mitigation proposal. In June 2005, Julia participated on panel discussing market monitoring issues, as well as market power safeguards for wholesale electricity markets. In 2004, she also provided testimony on pricing safeguards proceeding, which looked at alternative market power testing procedures for market power, analyzed implications on investment, and discussed efficiency consequences of certain bidding behavior. She also prepared and filed comment testimony and quantitative analysis on questions of market definition and market integration for the Public Utility Commission review in Project No. 29042. [In November 2005, pursuant to PUCT decision, both Project Nos. 24255 and 29042 were rolled into the PUCT Project No. 31972.]
- ***served as independent evaluator and RFP manager for the Connecticut Department of Public Utility Control's ("DPUC") request for proposals for incremental capacity:*** LEI was retained by the Connecticut state regulator to help realize a legislated mandate to hedge the risks of

evolving capacity markets and import constraints through a competitive RFP aimed at securing incremental capacity located electrically in the state of Connecticut. LEI analyzed the range of investment needs that could be required in Connecticut over the next 15 years due to localized ISO-NE markets for capacity and forward reserves. LEI then designed a procurement process, including the RFP and associated contracts. The RFP solicited for that capacity from both supply side and demand side resources. LEI served as the RFP manager for the process, and provided independent evaluation services of the bids, and recommending the winning portfolio. LEI also served as the DPUC's expert witness in the hearings approving the winning portfolio. LEI's analysis helped the DPUC successfully defend the contracts from legal appeal. [DPUC Docket No. 05-07-14PH2]

- ***prepared MBR authorization:*** In the matter of Hawk Nest Hydro LLC acquisition of Hawk Nest-Glen Ferris Hydroelectric Project Julia and the LEI team prepared the MBR Authorization for the FERC filing. [FERC Docket No. ER06-1446-000]
- ***performed market power analysis:*** Bear Swamp Power Company LLC (a pumped storage generation unit) asked LEI to perform a market power analysis in conjunction with Bear Swamp's application for market-based rate authorization. A similar study was done for Carr Street Generating Station L.P., Erie Boulevard Hydropower L.P., Brascan Power St. Lawrence River LLC, and Piney and Deep Creek LLC. [FERC Docket No. ER05-639 et al]
- ***provided testimony regarding the price elasticity of demand for transmission service:*** In the context of a transmission rate case for Hydro Québec TransÉnergie, and consideration of alternative transmission rate designs, Julia led an economic analysis on behalf of Brascan Energy Marketing, Inc. that examined the impact on trade from increased transmission costs, involving multi-factor regression analysis of nodal electricity prices, price spreads across markets, and interchange flows (imports and exports) across borders. Julia also considered the impact of the elasticity of demand for transmission services between Canadian provinces and US markets in the Northeast for maximizing revenues in rate setting. Julia presented oral testimony at the Régie de l'Énergie du Québec. [Dossier R-3549-2004]
- ***testimony regarding confidentiality of long range supply and demand forecasts by California utilities:*** LEI represented the California Energy Commission ("CEC") staff in a CEC and in a state regulatory proceeding at the California Public Utilities Commission ("CPUC") in respect of the merits of making public the investor owned utilities long range energy and capacity supply forecasts, as part of the integrated resource planning process. LEI served as an independent expert and supported the CEC in successfully arguing for the release of certain information, despite the utilities' assertions that such data would undermine competitive markets. [CPUC Rulemaking No. 05-06-040]
- ***monitored power procurement processes for Connecticut Light & Power***: The Department of Public Utility Control retained the services of LEI to assist the DPUC in monitoring the power procurement processes for Connecticut Light & Power's (CL&P) Transitional Standard Offer auction in November 2004 for services in 2005 and 2006, and once again selected LEI in September 2005 to monitor the November 2005 auction for services in 2006. Julia led LEI's team in providing advisory services to the DPUC, including guidance on communications protocols, design of sales contract agreement (between CL&P and winning bidders), and also

valuation of final bids vis-à-vis the forward market alternatives available to the utility. In November 2004 and 2005, Julia filed an affidavit after completion of the procurement process which the Commissioners used to approve the process and the contracts between CL&P and the winning bidder. [DPUC Docket No. 03-07-18PH02]

- ***prepared expert testimony related to horizontal market power considerations:*** In support of various acquisitions by IPPs spanning many years, Julia has prepared expert testimony for filing with FERC, related to Market-based Rate Authorization applications, Triennial Reviews, and Section 203 (merger) applications. LEI has a 100% track record in getting its clients' applications for market-based rate authority and/or mergers approved by FERC.

Market design work

- ***retained by the Massachusetts Attorney General's Office ("MA AGO") to evaluate wholesale market design efforts by ISO-NE to address fuel security/winter-time energy reliability issues:*** LEI staff assisted the MA AGO in 2018 and 2019 to evaluate the problem statement and the market design fixes being proposed by ISO-NE staff as well as other NEPOOL market participants to identified natural gas fuel-related limitations of the existing fleet in the face of retiring resources. In early 2019, LEI has also made a counter-proposal for an energy storage-based ancillary services product and adjustments to the existing capacity market design. LEI supported the MA AGO throughout the Markets Committee stakeholdering process in 2019.
- ***provided independent guidance to Alberta stakeholders on electricity market reforms in the face of evolving environmental and electricity industry policy:*** LEI supported the largest independent power producer in Alberta through the initial negotiations around climate change policies, including introduction of a renewable investment program, coal generation settlement, carbon taxation, and design of a capacity market. More recently, LEI has been involved in nearly two years of industry consultation and stakeholdering on what kind of capacity market design to introduce in the Province. LEI staff worked closely with several industry participants and have presented at AESO-led working groups on a variety of issues, including the setting of the demand curve, and market power rules and regulations.
- ***reviewed different energy market designs for a large Canadian generator:*** LEI performed a case study-oriented comparative review of energy-only and energy and capacity markets in North America and abroad, with lessons learned from other jurisdictions. LEI's work plan called for the simulation modeling of three forms of market design: an energy-only market, an energy and capacity market akin to Eastern US RTO markets, and a hybrid market with long term contracts and a spot market for capacity. The third phase involved the creation of a customized tool for future analysis, based on the simulation modeling results.
- ***advised on policy and government framework to Malaysia client:*** LEI was engaged by Tenaga Nasional Berhad ("TNB") to work as the project manager of its Incentive Based Regulation ("IBR") submission the entire vertically integrated electric utility enterprise. LEI provided advise on the policy and government framework for the implementation of IBR, providing strategic advice to IBR Council and TNB management regarding the IBR submission, managing and monitoring the submission process, coordinating with business entities and attending IBR Council meetings, progress meetings, and challenge workshops.

Moreover, LEI reviewed the current Regulatory Implementation Guidelines ("RIGs") set by the Energy Commission and proposed enhancements to the RIGs. LEI is also currently involved in negotiations with the Energy Commission regarding proposed changes to the RIGs. LEI is also updating and providing enhancements to TNB's Revenue Requirement Model ("RRM") which sets the IBR tariff for each business entity. Furthermore, LEI assisted in the writing of the IBR submission report to the Energy Commission.

- ***advised government agency on best practices for competitive procurement of new generation:*** LEI was engaged by a system operator to help advise on structuring of its renewable policy-driven procurements. LEI advised on commercial structure, terms, and process through case study analysis and lessons learned.
- ***Advised large generators on market mitigation approaches for an energy only market:*** LEI assisted the executive team in preparing a conceptual strawman for effective ex ante market power mitigation which is consistent with scarcity pricing.
- ***prepared an independent white paper reviewing the merits of various expert's positions with respect to re-design of the competitive retail market in New York and imposition of price caps on competitive retail providers based on the embedded costs of incumbent utilities:*** LEI staff, led by Julia, reviewed the competition-related testimony of various experts in the retail case proceeding before the NY PSC and provided an independent critique of the substantive arguments (and flaws thereof). LEI concluded that certain experts that had filed testimony mis-defined the market for competitive retail services, and mis-applied standard concepts in competition theory and anti-trust policy. LEI proposed alternative theories for observed price differences and customer switching trends.
- ***evaluated and critiqued Ontario's Market Renewal initiatives:*** On behalf of an IPP operating in the Ontario market, LEI reviewed and evaluated market reforms being proposed by the Independent electricity System Operator ("IESO"), including development of an internal nodal energy market, and addition of a capacity auction. LEI conducted simulation-based modeling to assess the impact of the reforms on market prices and investment in the province.
- ***advised private clients on the intersection of state and Federal policies in wholesale market rules and specifically MOPR-related issues in organized capacity markets:*** LEI modeled the latest proposals from PJM and stakeholders on its evolving MOPR design, and compared and contrasted the rules with ISO-NE's FERC-approved solution for dealing with investments mandated by state policy (e.g., CASPR). LEI advised clients on FERC strategy and discussed opportunities for existing resources to enhance end-of-life economics via the CASPR.
- ***presented to the NYISO Integrating Public Policy Task Force ("IPPTF") regarding proposed changes to the energy market to include social cost of carbon:*** LEI advocated in committee meetings for neutrality of treatment between imports and local resources in setting of the carbon adder in the locational price of energy. LEI staff presented at the IPPTF meetings in April 2018.
- ***conducted an empirical analysis of market design change to the Forward Capacity Market to align with states' clean energy initiatives:*** Specifically, LEI examined the Competitive Auctions with State Policy Resources ("CASPR") proposal from ISO-NE. The CASPR proposal involves adding a second or "substitution" auction to the current Forward Capacity

Market ("FCM") framework. LEI examined the fundamentals for this substitution auction and integrate it within Contractor's overall FCM model. LEI evaluated the financial incentives for incumbent (existing) resources to remain in operation versus the financial incentive to retire (and therefore the bidding strategy of these resources). LEI considered critically the tradeoffs that existing generators will be making in the face of the substitution auction, including the opportunity/risk of continuing to operate versus the opportunity/risk of submitting a retirement bid and participating in the substitution auction.

- ***advised client on electricity capacity product:*** LEI advised the California Energy Commission and other stakeholders on the design and development of a web-based software system supporting the trading of an electricity capacity product tracked by state regulators in connection with resource adequacy requirements. LEI analyzed similar systems in other jurisdictions, defined potential core functionalities of the California system – including, for example, posting of bids and offers. The engagement also required LEI to track titles, examine bilateral and/or multi-lateral trades and compliance reporting. LEI conducted a survey of industry participants to identify required and desired system capabilities.
- ***assisted in strategizing for the upcoming Clean Energy RFP:*** For a leading New England law firm, LEI modeled a number of potential eligible projects that could offer into the RFP, and then performed a mock evaluation, with various cost-benefit ratios. Through this analysis, LEI identified key drivers and assumptions that could affect project ranking.
- ***market design in support of electricity sector restructuring in Greece, specifically consideration of alternatives to physical divestiture of generation assets:*** On behalf of PPC, the government-owned vertically integrated national utility, LEI examined the following options: virtual power plant ("VPP") auctions, contract for difference ("CFD") and physical energy swaps. In case study format, the various options were compared against the following criteria: instrument objective, contract structure, contract terms, sale platform, settlement structure and the extent of physical control right transfer. Real-world experience from France, UK, Belgium, Denmark, Netherlands, Australia, and Alberta (Canada) helped shape the discussion of comparative advantages and disadvantages, taking into account the unique concerns for Greek policymakers.
- ***conducted modeling and forecasting related to the Alberta government's recent announcements to transition to a capacity market and continue meeting its carbon emissions reduction plans:*** as part of this engagement, LEI developed several scenarios that evaluated the impact of various policy and market related changes in the Alberta market on incumbent and new generators in the province. These changes included market design (energy only or energy & capacity market), plants' retirements/repowering plans, varying carbon tax regimes and different renewable investment targets. Results from these scenarios were designed to identify specific operational and regulatory risk for the client and develop a strategic best-response to optimize the client's portfolio in light of these uncertainties.
- ***prepared white paper for Canadian electricity regulators and utilities on the comparative advantages and drawbacks of various tariff-setting regimes, from performance-based regimes to cost-of-service:*** This project involved a general overview of tariff-setting practices across Canadian provinces as well as highly detailed Canadian and international case studies and an examination of the key-lessons to be learned from each case. Detailed case studies

covered the tariff-setting regimes in place in the UK, the Australian National Electricity Market and the Netherlands. As part of its deliverables, two workshops were conducted with a variety of regulators and utilities.

- ***assisted a client with certain matters pertaining to a FERC investigation:*** Specifically, the scope of this retention includes economic and market analysis in support of a market participant in ISO New England's day ahead load response program ("DALRP"). Julia also provided affidavits and deposed in connection with FERC investigation of behind-the-fence industrial generator and participation in a wholesale power market in New England. Julia helped the client to respond to assertions of market manipulation and estimate market benefit provided through its participation in demand response program.

Electricity and Natural Gas Asset Valuation and Transaction Advisory Work

- ***assisted in the evaluation of generation and distribution assets across several Caribbean and Asian island power systems:*** LEI provided a preliminary valuation of various overseas generation and distribution assets located on island systems in the Caribbean and Asia to potential hedge fund looking to acquire the portfolio. LEI prepared a due diligence dossier for each asset, including (1) a plant by plant summary pro-forma financial model of cash flow (and recommendations surrounding the appropriate cost of capital that should be used to appraise each asset); 2) review of public financial statements, where available, and assessment of projections prepared by the seller; 3) examination of regulatory documents related to the assets or subsidiaries; 4) summary of the key terms and conditions of the major power purchase agreements relating to target power plants; 5) and a risk assessment, discussing major issues regarding each asset and/or business entity. LEI also identified other possible purchasers of these assets.

- ***estimated the stranded cost obligation:*** on behalf of a cooperative, LEI prepared an estimate of the stranded cost obligation it would need to pay, pursuant to FERC's standards, in order to exit its membership in a large, Midwestern generation & transmission authority. In order to prepare this analysis, in advance of litigation, LEI reviewed precedent cases and settlements before the FERC and conducted long term price forecasts for the market value of energy and capacity in the MISO market.

- ***valuation for a cogeneration project:*** LEI assisted a private equity firm with valuation of a large urban cogeneration facility in the Northeast US. LEI developed a dispatch profile and calculated all electricity, steam, environmental, and maintenance revenues and costs to determine the gross margins of the plant for the next 20 years; LEI's analysis was prepared for purposes of independent asset valuation.

- ***analyzed opportunity for a transmission tariff rebate based on going forward financial viability of a customer:*** LEI was engaged by Emera Maine, a transmission utility in Maine, to assess the financial viability of a customer to continue to operate several power plants in coming years with and without a transmission tariff rebate. LEI's analysis supported public discussions regarding the transmission rebate and a FERC filing by Emera Maine.

- ***research paper demonstrating best practices for measuring the benefits of transmission*** for a WIRES-funded research project, LEI prepared a "how-to" guide and demonstrated its application on two hypothetical transmission projects, showcasing how system planners and other decision-makers can measure objectively the benefits of transmission investment from the perspective of various stakeholders, and also over the short- medium- and longer-term.
- ***devised an innovative approach for evaluating the economics, environmental, and siting costs and benefits of transmission (and generation investment) for the California Independent System Operator:*** building upon the traditional economic framework for cost-benefit analysis, the LEI team devised an approach to quantitatively value the expected net benefits from various infrastructure projects, taking into account market uncertainties as well as the classic deregulated market coordination problem of planning for transmission give uncertain generation investment and vice versa. A scoring technique for environmental permitting and siting issues was also developed, in order to quantify the potential impact of the proposed project on the local environment and economy, as well as to measure the impact of such factors on the project timetable and eventual net benefits to society. Real option techniques were also considered in this engagement to assess the potential value of uncertainty and the benefits for delaying various investment strategies. The methodology was also expanded to handle the potential to evaluate numerous competing projects, in recognition of the fact that transmission and generation investments (and other potential investments) could be both complements and substitutes.
- ***price forecasting for wind facilities:*** LEI analyzed the revenue potential for wind facilities in CAISO, SPP and PJM, developing price forecasts through 2045 and also assessing market rules to identify any potential penalties that may apply to intermittent generation and deviations from generation profiles. Three cases of merchant forecasted revenues, Base Case, High Case and Low Case, were developed in order to identify key uncertainties and opportunities.
- ***served as Independent Examiner for a proposed merchant transmission project's Open Solicitation process***: The project entailed designing the solicitation process, meeting with potential shippers on the line to garner early interest, drafting announcements and press releases, conducting information sessions, updating the solicitation website, evaluating and ranking bids, assisting with bilateral negotiations with shippers, and submitting a report to FERC as part of the developers' Section 205 filing.
- ***conducted independent analysis on power market in support of transmission development:*** LEI supported a major transmission developer in the Northeast US in its analysis of opportunities and market impacts from a number of potential projects to bring energy into the New England region. LEI performed independent analysis measuring the impacts of numerous project designs on the power market (including energy and capacity markets, production cost savings and environmental benefits) and local macroeconomic analysis as well.
- ***assessed market opportunities for industry-scale battery storage technology in the US and selected European jurisdictions for energy arbitrage and ancillary services provision:*** Under this assignment, LEI modeled the operation regime of a battery operating in energy and ancillary services markets in order to monetize added revenues for a wind and solar

generators. Findings and modeling results were analyzed and presented before the client's management team and were then deployed to develop strategy for marketing battery technology to renewable developers and utilities. Another objective of the project was to identify most suitable markets and products to optimize the strategy of the battery's market entry.

- ***conducted wind price forecasting:*** LEI used its proprietary dispatch model, POOLMod, to project energy prices in ERCOT for a wind developer undertaken financing of its projects in West Texas. LEI also examined the implications of PPA related to the two wind farms. LEI also provided energy, capacity, and solar renewable revenues for an operating solar plant in New Jersey as part of the same engagement.

- ***reviewed energy storage installations in New England:*** For a transmission and distribution company in New England, LEI analyzed the cost and benefit to consumers on different configurations of energy storage installations in the ISO-NE grid. The engagement involved modeling multiple configurations of energy storage solutions, including different storage capacity and duration, as well as various charging and discharging cycles.

- ***performed analysis of HVDC transmission projects:*** LEI was retained by a transmission developer to perform a high-level analysis of the cost-competitiveness of HVDC transmission as a regulated solution with respect to generation resource. The work included comparing the revenue requirement for HVDC transmission projects with the net Levelized Cost of Entry (LCOE) of comparatively sized and located generation resources.

- ***supported a risk management assessment:*** LEI assisted in a large provincial institution in the development and assessment of alternative risk management and investment strategies for its trading and investment businesses. As part of this work LEI completed a Risk Assessment Survey of the Board of Directors as well as additional Value-at-Risk ("VaR") modeling, scenario and stress testing.

- ***engaged by an investment firm in association with its acquisition of a proposed natural gas-fired plant:*** Work involved asset valuation, due diligence support and market analysis. LEI reviewed the documents in a virtual data room, and performed analysis related to drivers of gross margin for the asset: macroeconomics, fuel and electricity cost projections, and overview of gas and electricity market in the region where the asset was located. Power plant was successfully financed and constructed; LEI's economic analysis and support was critical to the financing and structuring of the plant's capitalization and risk management strategy for participating in the wholesale competitive power market.

- ***performed strategic analysis of the value of on-site peakers for an industrial client:*** LEI was engaged by an industrial client in Alberta that was considering the addition of on-site gas peakers. LEI's scope of work consisted of identifying potential technology type candidates that would suit the client's needs, reviewing historical and projected site loads, developing a status quo estimation for the cost of delivered power rates, and finally creating a relative economic model that compared the use of on-site generation against the status quo.

- ***implemented a portfolio optimization strategy:*** LEI was engaged by an entity controlling a significant generation portfolio to explore options associated with entering into a service agreement with a third-party. LEI prepared a report which identified a number of firms which

could provide this service, and provided a more detailed profile of the firms which best meet the requirements of the client. LEI also acted as an independent advisor to guide the client through a process to potentially contracting with a third-party service provider.

- ***provided forecasting and modeling support for a start-up company:*** Julia and her team assisted Tres Amigas LLC, a start-up company on the revenue forecasting and modeling for the second stage financing. The start-up company aims to develop, own and operate a unique three-way AC/DC transmission facility located in New Mexico. In 2010, for the feasibility analysis stage, LEI provided extensive transmission evaluation, financial modeling, price forecasting, and market analysis for the markets, including the Arizona/New Mexico/Southern Nevada sub region of the Western Electricity Coordinating Council, the Electric Reliability Council of Texas, and the Southwest Power Pool. LEI's analysis support over $15 million of development stage funding.
- ***led research on biomass plants regarding renewable energy revenue options:*** Julia investigated opportunities for portfolio of biomass plants to earn renewable energy revenues from RECs, capacity markets, and carbon offsets given regulations in all states belonging to MISO, PJM, and ISO-NE. Engagement also involved formulating strategies for client to optimize the generation assets' revenue potentials by exploiting the identified renewable energy opportunities.
- ***assisted a New England incumbent utility in evaluating the economic benefits of two solutions aiming to relieve energy congestion in the metropolitan area of Boston:*** LEI modeled various transmission solutions. The objective of the economic analysis from the energy market perspective was to examine whether there are any production cost savings or market price ("LMP") impacts from either proposal, and to describe under what conditions (assumptions) these benefits are realize.
- ***prepared a 10-year energy market price outlook for the New England wholesale power market and forecast the impact of a proposed project on New England market prices:*** LEI also determined the benefits of the proposed transmission project on employment, economic activity, and tax revenues in New England. LEI utilized the dynamic input-output ("I/O") economic model developed by Regional Economic Models, Inc. ("REMI") to measure the economic benefits to various New England states from the project on employment, economic activity, and tax revenues. LEI separated the economic impact caused by the construction of the project, and the impact caused by the reduction in energy prices due to the commercial operation of the project, taking into account issues such as usage of electricity in residential, commercial, and industrial sectors in the region, and also existing long-term energy contracts that would limit the impact of the project.
- ***analyzed the potential investment opportunities for a large IOU in energy storage in New England:*** Through intensive research and analysis, including simulation-based modeling, LEI identified potential opportunities for energy storage investment in New England and prepared estimate of societal benefits from such investment.
- ***analyzed revenue/gross margin modules for a district cooling asset being considered for acquisition in Midwest US city:*** Under this engagement, LEI performed a due diligence review of the information received from the seller (including documentation from the data

room) and designed a series of models aiming at quantifying the asset's potential revenues. Part of LEI's scope work also consisted of identifying and assessing the opportunities to enhance and extend the customers base. LEI also evaluated the risks associated with prospective/existing customers forgoing the asset's services in exchange of self-supplying their cooling needs.

Regulatory Economics

- ***reviewed Eversource's internal non-transmission alternatives analysis and conducted a fatal flaw analysis:*** LEI also prepared an analysis describing qualitatively the challenges to various NTA solutions identified in Eversource's internal analysis for a major urban reliability-focused transmission project. LEI also conducted an independent analysis to estimate the costs of any possible NTA solutions. This involved talking to engineering firms, other utilities (on a no-names basis) and gathering specific data on DG and micro grid generation installations. LEI also commented on the practical feasibility/challenges associated with siting specific NTA technologies in the project region.
- ***conducted Total Factor Productivity study:*** In December 2014, LEI prepared a report for Ontario Power Generation ("OPG") entitled "Empirical Analysis of Total Factor Productivity Trends in the North American Hydroelectric Generation Industry." The purpose of this report was to share findings from LEI's TFP study, which estimated TFP trends for a select group of peers from the North American hydroelectric generation industry. Data for this study covered an eleven year period from 2002-2012. The purpose of this new engagement is to update this study for newly available data (encompassing operating costs and other statistics for calendar years 2013 and 2014).
- ***assisted an electricity generator in performing efficiency analysis on their assets to fulfill the regulators:*** LEI proposed a structured approach to address how productivity should be measured, what methods are available, identify a relevant peer group, and ultimately provide the client with an empirical study for filing with the regulator.
- ***prepared a study of the Value of Lost Load ("VoLL") in ERCOT and evaluated current utility practices for manual load shedding:*** LEI's report on VoLL was filed with the PUCT in June 2013 under PUCT Docket 40000.
- ***counseled on transmission cost allocation:*** LEI advised Maine Public Utilities Commission on methodologies for transmission cost allocation by comparing and contrasting alternative planning approaches and pricing models employed within the US and one international jurisdiction, the United Kingdom. The final report provided a 'strawman' recommendation for an effective cost allocation methodology, which was used by the Maine PUC to guide it in its filings at FERC related to Order 1000 and the preceding NOPR on the same issue.
- ***served as Independent Monitor for the competitive solicitation of service by a utility:*** Julia acted as manager for LEI's engagement with the City of New Orleans. LEI was engaged to act as the independent monitor for Entergy New Orleans' solicitation of a Third Party Administrator to implement and deliver conservation and demand management programs on behalf of the utility. LEI provided guidance to Entergy and the City on the development

of the request for proposals, including mandatory requirements and commercial terms. LEI oversaw the bid receipt as well as the review and selection process. A final report was provided outlining LEI's opinion as to the fairness of the overall process.

- ***performed benefits analysis on proposed New York transmission line:*** LEI performed an analysis of benefits to NY consumers from a proposed transmission line between New York State and New England, analyzing the impacts from the proposed project's investments on GDP, jobs, tax revenues, and system reliability. LEI also performed a cursory review of the proposed project's environmental impact, based on criteria established by the NY DPS Staff in previous cases before the Public Service Commission

- ***authored paper on transmission and market resource alternative investments:*** LEI was engaged by WIRES, a US-based transmission association, to prepare a White Paper on Market Resource Alternatives ("MRAs") which provides external parties with a clear understanding of MRAs and a concise description of how MRAs can work effectively alongside transmission investment in US power markets to support market development, reliability, and cost-effective supply.

- ***provided expert analysis and insight on how the restructuring of the US electricity markets has affected the economics of nuclear power plants:*** For a Japanese research institute, LEI provided a Briefing Memo that responded to discrete questions related to the role of government, and the impact restructuring had on nuclear plant operations and financing.

- ***performed a review and analysis of rate making approaches applied to the client's capital expenditure profile including demonstration of the negative potential impact of "I-X" rate making approaches on a utility's ability to earn a fair return:*** The objective of this engagement was to demonstrate to stakeholders and the Ontario Energy Board the reasonableness of the revenue cap per customer model that the client has previously relied upon and planned to propose in its next ratemaking review Furthermore, the secondary objective was to conceptualize the insufficiency of the "I-X" regime, even with a revenue cap per customer model, in consideration of the fair return standard and given the client's business is operating in an environment where substantial capital expenditure needs are projected over the next Incentive Regulation Plan ("IRP") period. Docket Number EB 2012-0459

- ***testified in front of the New Mexico Finance Authority Oversight Committee regarding the potential economic benefits of new investment in transmission in the state of New Mexico:*** Julia considered the impacts of local spending during construction of the proposed HVDC project on the state economy, using BEA RIMS multipliers to estimate the boost to economic activity. Julia also employed the DOE's JEDI model to estimate the potential for new jobs and GDP growth as a result of new renewables development in state (wind and solar) as a result of the transmission access that would be provided by the HVDC project.

- ***provided independent review of market benefit reports regarding repowering of an existing generator:*** LEI was engaged by NRG to provide an independent review of the economic analysis in two reports: "Report and recommendations comparing repowering of Dunkirk Power LLC and transmission system reinforcements", published by National Grid ("NG") on May 17, 2013, and "NRG Dunkirk Repowering Project Economic Impact Analysis", published

by Longwood Energy Group LLC ("LEG") on March 20, 2013. Both reports forecasted market benefits, production cost savings and macroeconomic benefits. LEI's review compared methodologies and assumptions used by each report, and how these may have affected their results; LEI's review was subsequently submitted by NRG to Case 12-E-0577 at the New York Public Service Commission.

- ***conducted macroeconomic analysis of HVDC project:*** Julia was part of a team of economists that performed a macroeconomic analysis to estimate the local economic benefits accruing to taxpayers, residents, and businesses along the 800+mile route during construction of the Zephyr HVDC project, which runs from Wyoming to Colorado, Utah, and Nevada. LEI performed the analysis using the REMI P1+ model.
- ***conducted regulatory review in PJM:*** LEI was hired to review regulatory and market drivers of energy and capacity prices in PJM, and forecast prospective revenues of a portfolio of pumped storage and conventional hydro generation facilities offered by FirstEnergy, over a 20 year horizon.
- ***conducted market analysis the value of new transmission to interconnected different parts of the New England grid:*** LEI performed a fifteen (15) year simulation analysis to estimate the market impacts resulting from a new transmission interconnection (covering the timeframe 2015-2029) and project the impact on Maine customers (including Northern Maine customers). LEI evaluated the market evolution with and without the interconnection and described the potential ramifications for purchasing electricity for Northern Maine customers. The analysis also estimated the potential impact on ratepayers from the re-allocation of the ISO-NE Pool Transmission Facility rate to incorporate the Northern Maine load and franchise area under a pro forma 10-year transitional agreement. LEI performed the modeling using our up-to-date ISO-NE simulation model (which covers the energy and capacity markets), extended to represent in detail the Maritimes control area.
- ***prepared presentation material on the electricity market impacts and the benefits of Northern Pass Transmission project for New Hampshire and New England consumers:*** In addition, LEI staff assisted the client in preparation of an op-ed piece for dissemination to New Hampshire press outlets. LEI staff also attended an internal company meeting and testified on behalf of the client. Lastly, LEI staff assisted in the preparation for and attended the live New Hampshire Public Radio program "The Exchange" to discuss the benefits of the Northern Pass Transmission over the hour-long live show.
- ***authored report on capital expenditure recovery mechanisms:*** For a Canadian client, Julia prepared a report that looks into the different capital expenditure recovery mechanisms utilized in four markets namely Australia, New Zealand, Ontario, and the UK for electric network utilities. The report also provided different options that the client can propose for its performance-based ratemaking filing.
- ***assisted the Maine Public Utilities Commission in developing an electric resource adequacy plan to aid MPUC in the development of a strategy for the pursuit of the long-term contracts:*** The LEI team, led by Julia, submitted a report that builds up a set of recommendations for a long-term investment strategy based on an analysis of the current supply-demand situation, a review of the existing wholesale market rules for energy and the Forward Capacity Market,

an examination of historical price trends, and review of the investment needs assessments prepared by the utilities and ISO-NE, as well as relevant sub-regional planning studies.

- ***analyzed electricity industry in a Midwestern state:*** To satisfy the requirements of a recently passed statutory mandate, Julia and the LEI team conducted a broad-based analysis of current practices and the potential for reform within Kentucky's electricity industry in four areas: (i) energy efficiency and demand side management; (ii) use of renewables; (iii) full cost accounting; and (iv) tariffs. Reported results to the state's regulatory commission, including a full set of recommendations in each of the four areas for overcoming existing impediments to legislative objectives for improvements in the industry's overall efficiency and reductions in its environmental impact.
- ***offered feedback on benchmarking methodology:*** Julia provided comments on the benchmarking methodology suggested by OEB consultants, looking at the analytical aspects of defining and benchmarking the performance of multiple utilities across long period of time. The critique provided details on how each criterion affects the benchmarking study and what are the remedies available to improve the results.
- ***reviewed power purchasing options at a large industrial customer's Southeastern facilities over three years:*** LEI assessed the probability of a supply interruption over the next three years due to the state of the transmission system in this region. LEI also assessed the facility's options for purchasing power for this load in the wholesale market or through bilateral negotiated contracts with third party (non-utility) suppliers.

SPEAKING ENGAGEMENTS AND PUBLICATIONS:

"Reflections on US Market Developments", IPPSA Annual Conference 2019, Banff, Alberta. March 12, 2019.

"Outlook for US Eastern Electricity Markets: ISO-NE, NYISO and PJM", Bank of America Merrill Lynch 2019 Ga, Power and Solar Leaders Conference, Boston, Massachusetts. March 5, 2019.

"Alternate Regulatory Approaches" CAMPUT 2018 Conference. May 10, 2018.

"The Transformation of the Energy Sector" and "Role of Women in Energy" SIPA's Women in Energy Event at Columbia University. March 28, 2018.

"Market pricing of oil: are there lessons for the electricity market?" Gulf Coast Power Association 31st Annual Spring Conference - Session VIII -Valuing Dispatchable Resources, Houston, Texas. April 20, 2017.

"Studying the impact of environmental policies on electricity market design." AIEE Energy Symposium: Current and Future Challenges to Energy Security, The University of Milan – Bicocca, Milan, Italy. December 1, 2016.

"Energy storage – how will it be part of "Grid of Things" in the future?" WIRES' 2016 Spring Meeting. April 16, 2016.

"Implications of Energy Infrastructure Investment on Local Economies in New England," REMI E3 Conference 2015: Energy, the Environment and the Economy, Amherst, Massachusetts, United States. July 30, 2015.

"Renewables: No Longer a Noble Way to Lose Money?" Moderator. SuperReturn US 2015 Conference, Boston, Massachusetts, United States. June 15, 2015

"Perspectives on future trade opportunities between Canada and the US, and benefits to US consumers" EUCI US/Canada Cross Border Power Summit Conference, Boston, Massachusetts, United States. April 8, 2015.

"Are transmission expansions and upgrades compatible with both small and large scale clean energy?" Panelist. Southwest Clean Energy Transmission Summit, Albuquerque, New Mexico, United States. April 1, 2015.

"CEO Panel" Moderator. ABB Energy & Automation Forum, Calgary, Alberta, Canada. September 10, 2014.

"International Views and Addressing the Need for More Underground Transmission in the US" Panelist. Platts 2014 Transmission Planning and Development Conference: Ensuring Grid Reliability, Planning Timelines, and a Robust Market's Relationship with New Build, Arlington, Virginia, United States. June 18, 2014.

Julia Frayer "System Operator's Response to 1000 – How Can the Various Regions Work Together?" Moderator. Platts 2013 Transmission Planning and Development Conference, Washington DC, United States. September 23, 2013.

"Merchant Transmission: Planning and Development and Lessons Learned from North America," Integrated Transmission Planning and Delivery, Imperial College - Workshop for OFGEM, London, United Kingdom. January 11, 2013.

"Demand for wind in New England: an economist's perspective," AWEA Regional Wind Energy Summit, Portland, Maine, USA (with Shawn Carraher). September 5, 2012.

"Cost effective procurement of Renewables to Meet Policy Requirements," NECPUC Symposium, Rockport, Maine, USA. May 22, 2012.

"Best Practices for Transmission Asset Valuation," Transmission Grid Conference, London, United Kingdom (with Shawn Carraher and Yifei Zhang). March 16, 2012.

"How effective is US technology policy on clean energy." 30th USAEE/IAEE North American Conference, Washington, DC, USA. October 10, 2011.

"Are Markets Ready for New Energy Storage Technologies?" 34th IAEE, Stockholm, Sweden. June 21, 2011.

"Long Term Market Impact of Demand Response" 33rd IAEE International Conference, Rio de Janeiro, Brazil (with Furhana Hasani and Yunpeng Zhang). June 7, 2010.

"Applications of Information Policy Principles from Auction Theory in the Deregulated Electricity Market" 32nd IAEE International Conference, San Francisco, California (with Zvika Neeman and Matthew Wittenstein). June 21-24, 2009.

"Prepared Presentation of Julia Frayer for Market Monitoring and Surveillance in the context of Market Design." Panelist, PUCT Workshop for Project #28500, Austin, Texas. June 10, 2005.

"Written Statement of Julia Frayer for the January 27th 2005 Technical Conference in Docket RM04-7-000" Panelist, FERC Technical Conference, Washington D.C. January 27, 2005.

"Competitive procurement options for Ontario's LDCs" Speaker, APPrO 2004 Conference, Toronto, Ontario (Canada). November 24, 2004.

"Beyond market shares and cost plus pricing: designing a horizontal market power mitigation framework for today's electricity markets." *Electricity Journal* (with Nazli Uludere, and Sam Lovick). November 2004.

"Alternative to LMP pricing for transmission: a case study of the ICRP approach used by National Grid Company in the UK." Speaker, Electric Power Conference 2004, Baltimore, Maryland. March 31. 2004.

*"**The World Changed on August 14th: the (Second) Great Northeast blackout."*** Chairman of Panel Session, Electric Power Conference 2004, Baltimore, Maryland. March 30, 2004.

"Big ticket leasing - what next for the future?" Panelist, Big Ticket Leasing 2003, London (United Kingdom). March 12, 2003.

"Evaluating the Electron Highway" Speaker, IPPSO 2001 Conference, Richmond Hill, Ontario (Canada). November 2001.

"What is it worth? Application of real options theory to the valuation of generation assets" *Electricity Journal* (with Nazli Uludere). November 2001.

"X Marks the Spot: How UK Utilities Have Fared Under Performance-Based Ratemaking" *Public Utilities Fortnightly* (with AJ Goulding and Jeffrey Waller). July 15, 2001.

"How much is it worth? Applying real options valuation framework to generation assets" Speaker, Electric Power 2001, Baltimore, Maryland. March 22, 2001.

"***Dancing with Goliath: Prospects After the Breakup of Ontario Hydro***" *Public Utilities Fortnightly* (with AJ Goulding and Nazli Z. Uludere). March 1, 2001.

2 Exhibit B: Qualifications for London Economics International LLC

2.1 LEI's qualifications related to island systems

- ***conducted a multi-year study evaluating various utility business models and regulatory frameworks:*** LEI prepared a study to assess options for transforming the ownership and regulatory model used to govern its electricity sector in Hawaii. This was a large and significant initiative that provided the government of Hawaii with independent and objective research and analysis to help it scope out the most appropriate course of action in achieving Hawaii's overarching policy goals. There were four main phases to this work: 1) to determine the long-term operational and financial costs and benefits of electric utility ownership models to serve each county of the State of Hawaii; 2) to determine the long-term operational and financial costs and benefits of electric utility regulatory models to serve each county of the State of Hawaii; 3) to provide additional insight and analysis of ownership and regulatory model changes possible under the models identified and recommended; 4) to provide for the development and delivery of the executive summary, formal presentation, and final report in a format approved by the client.

- ***evaluated generation and distribution assets across several Caribbean and Asian island power systems:*** LEI provided a preliminary valuation of various overseas generation and distribution assets located on island systems in the Caribbean and Asia for a hedge fund looking to acquire the portfolio. LEI prepared a due diligence dossier for each asset, including (1) a plant by plant summary pro-forma financial model of cash flow (and recommendations surrounding the appropriate cost of capital that should be used to appraise each asset); 2) review of public financial statements, where available, and assessment of projections prepared by the seller; 3) examination of regulatory documents related to the assets or subsidiaries; 4) summary of the key terms and conditions of the major power purchase agreements relating to target power plants; 5) and a risk assessment, discussing major issues regarding each asset and/or business entity. LEI also identified other possible purchasers of these assets.

- ***provided expert support to government in a review of the utility's rate of return:*** for the Hong Kong Government, in 2012, LEI reviewed the rate base and the rate of permitted return (allowed return on capital) for the power companies in Hong Kong under the Scheme of Control Agreements. This required reviewing the alternatives to using Average Net Fixed Assets as the rate base, examining the assumptions used and methodology to calculate the weighted average cost of capital for the power companies, updating the indicative range for the permitted rate of return, and recommending changes to existing rates of return by identifying new international best practices.

- ***performed a second review of electricity regulatory framework:*** LEI was retained by the Hong Kong Special Administrative Region government to assess certain aspects of the Hong Kong regulatory regime for electricity, such as cost of capital, ratebase calculations, efficiency incentives, and fuel cost pass through mechanisms, in order to help prepare the Government for negotiations with the utilities to change the regime after current agreements expire.

- ***supported M&A transactions involving Singapore-based power plants:*** on behalf of a large Asian generating company, LEI provided revenue forecasts from spot, retail, and vesting contracts for a Singapore generator that was being divested by the national monopoly. Analysis included review of repowering options, assessment of regulatory evolution, and potential for strategic behavior. The LEI team later performed a similar due diligence and asset valuation for another Asian generating company also seeking to purchase assets in Singapore, as well as subsequently assisting in analysis associated with refinancing of the acquisition.

- ***assessed the economics of generator repowering on Long Island:*** LEI was engaged by a municipality in Long Island to evaluate the market value of existing power plants, and consider the ratepayer implications around Long Island Power Authority's ("LIPA") plans for repowering and retirement of some of its plants relative to new construction and power purchase opportunities. LEI provided a critical, high level review of wholesale market costs, and ultimately the retail rate impact assessment. LEI also analyzed the impact of LIPA's plans on local property tax revenues.

- ***implications of performance-based ratemaking ("PBR") in the Caribbean:*** for a privately owned integrated electric company based on a well-developed Caribbean island, directed strategic analysis of implications of PBR, suggested approach to regulators, and provided indicative benchmarking analysis.

2.2 LEI's qualifications related to expert testimony

2.2.1 FERC proceedings related to electricity market design and regulatory issues

- ***On behalf of Columbia University Center on Global Energy Policy, AJ Goulding wrote on the Department of Energy's grid resiliency pricing rule,*** which instructed FERC to put in place cost-of-service mechanisms for power plants within limited time, to address threats to US electrical grid resiliency. The order appeared to be intended to prevent market-driven retirement of coal and nuclear stations that have been pressured by cheap natural gas and significant renewable additions. To reduce the order's distortionary impact, Mr. Goulding offered five steps ISOs could take to move forward. This paper was used to demonstrate the challenges that FERC and ISOs would face and recommended strategies to incorporate into ISOs' planning to limit the distortions. [Docket No. AD18-7-000]
- ***Testified on behalf of the NEPOOL in a jump ball filing at FERC regarding the Performance Incentive scheme proposed by ISO-NE for the capacity market:*** in written testimony submitted to FERC, Julia Frayer identified a shortcoming in ISO-NE's proposed performance incentive scheme for its forward capacity market. [Docket. No. ER14-1050 at FERC]

- ***Expert testimony before FERC related to Shell Energy's sale of capacity commitments from facilities in New York to New England in an alleged market manipulation case:*** in 2009-2010, Julia Frayer provided expert testimony before FERC related to Shell Energy's sale of capacity commitments from facilities in New York to New England in an alleged market manipulation case. Julia examined market rules, operating procedures, and

pricing arrangements in New England and New York at the time of the investigation, and examined the participation of Shell in the capacity markets and compliance offers in the energy markets, commenting on the economic rationale behind the client's must offer strategies in the energy market for capacity compliance. [EL09-48-000]

- ***Confidential FERC investigation in 2009-2010 of market manipulation in New England in respect of demand response resources and ISO-NE's day ahead demand response program:*** Julia Frayer and her team assisted the client with certain matters pertaining to a FERC investigation. Specifically, the scope of this retention included economic and market analysis in support of a market participant in ISO New England's day-ahead load response program ("DALRP"). Julia also provided affidavits and deposed in connection with FERC investigation of behind-the-fence industrial generator and participation in a wholesale power market in New England. Julia helped the client to respond to assertions of market manipulation and estimate market benefit provided through its participation in demand response program.
- ***Review of FERC's Standard Market Design ("SMD"):*** LEI examined issues related to the FERC's Standard Market Design and its implications for ERCOT and TXU. LEI assisted in the preparation of comments for submission to FERC in response to their SMD NOPR. In the course of producing these comments, LEI evaluated SMD's specific proposals and benchmarked them against best practices worldwide. (2002)
- ***Provided testimony regarding ISO-NE's tariff design:*** LEI submitted testimony on behalf of ISO New England to the FERC to help defend ISO New England's self-funding tariff. LEI first defined the basic underlying economic principles for specifying the tariff, and then undertook to show how the tariff should be applied to various system users. The engagement involved an intensive financial modeling effort, and frequent interaction with stakeholders. (2000) [ER01-316-000]

2.2.2 State PUC submissions

2.2.2.1 California

- ***Testimony regarding confidentiality of long range supply and demand forecasts by California utilities:*** LEI represented the California Energy Commission ("CEC") staff in a state regulatory proceeding at the California Public Utilities Commission ("CPUC") in respect of the merits of making public the investor owned utilities long range energy and capacity supply forecasts, as part of the integrated resource planning process. LEI served as an independent expert and supported the CEC in successfully arguing for the release of certain information, despite the utilities assertions that such data would undermine competitive markets. [CPUC Rulemaking No. 05-06-040]
- ***Integrated resource planning and application of portfolio analysis:*** LEI advised the California Energy Commission ("CEC") and other stakeholders on the use of Portfolio Analysis as a method for analyzing alternative options for the long-term development of portfolios of electricity generators to serve the California market. LEI outlined the core principles and techniques of Modern Portfolio Theory and its applications to the electricity industry and developed detailed case studies of several recent applications. LEI

presented results to the Commissioners along with recommendations for employing the techniques in California as part of the state's integrated energy planning process. (2006)

- ***Capacity market trading platforms:*** LEI advised the CEC and other stakeholders on the design and development of a web-based software system supporting the trading of an electricity capacity product tracked by state regulators in connection with resource adequacy requirements. LEI described the characteristics of similar types of systems in other jurisdictions; defined potential core functionalities of the California system – including, for example, posting of bids and offers; execution of bilateral and/or multi-lateral trades; title tracking; compliance reporting; etc. – and related features; and conducted a survey of industry participants to identify required and desired system capabilities. (2006) [CPUC, R. 05-06-040]
- ***Data confidentiality:*** LEI served as an expert witness on economic issues at the Resource Adequacy and Procurement Proceedings at the California Public Utility Commission ("CPUC") proceedings. LEI staff testified on economic issues related to pricing, investment signaling and data confidentiality in Resource Adequacy and Procurement Proceedings at the CPUC in November-December 2005 on behalf of the CEC. LEI authored direct and rebuttal testimony on these issues and testified in San Francisco in late November 2005. (2005) [CEC, 04-IEP-01D]
- ***Assessing the benefits of transmission expansion in reducing market power:*** Julia led LEI's advisory services to the California Independent System Operator, where she and her team devised an innovative approach for evaluating the economics, environmental, and siting costs and benefits of transmission expansion, which aimed to reduce the market power. The methodology was also expanded to handle the potential to evaluate numerous competing projects, in recognition of the fact that transmission and generation investments (and other potential investments) could be both complements and substitutes. [CPUC, Docket No. I.00-11-001]

2.2.2.2 Connecticut

- ***Conducted non–transmission alternative study for presentation to the Connecticut Siting Council***: LEI was hired to conduct a Non- Transmission Alternatives ("NTA") analysis for the two transmission projects, which are a component of larger transmission solution being proposed by Eversource and the Greater Hartford and Central Connecticut ("GHCC") area. The objective of the NTA analysis was to determine the feasibility and viability of other non- transmission resources- such as new generation and new demand-side resources- to be developed in lieu of these two specific transmission projects to relieve transmission reliability concerns. The NTA analysis [was] filed as part of Eversource's application with the Connecticut Siting Council ("CSC") for each of these transmission projects. [CSC Docket NO.474]
- ***NU-NSTAR merger review:*** in support of a client's opposition of a proposed NU-NSTAR merger, LEI analyzed the potential competitive market effects on a vertical scale and considered the extent of buyer market power for the purchase of standard service (full requirements) products. The testimony was submitted to the Public Utility Regulatory

Authority ("PURA"). In a later submission, LEI also analyzed the settlements reached or proposed in a number of recent utility mergers. (2012) [PURA Docket No. 12-01-07]

- ***Connecticut Siting Council application for permitting of the Greater Springfield Reliability Project:*** LEI simulated the New England wholesale electricity markets in order to compare the economic benefits between Greater Springfield Reliability Project ("GSRP") and responses to the Connecticut Energy Advisory Boards' ("CEAB") RFP for a non-transmission alternative ("NTA") to GSRP. The NTA consisted of modeling a new CCGT plant to be placed in Southwestern Connecticut. In order to ensure that economic benefits were not subject to the forced outage and availability schedule of the simulated energy markets, LEI simulated the energy market with 30 different random forced outage and availability schedules. In effect, these 30 different simulations added further robustness to LEI's results because it captured the flexibility of the New England energy market under several different normal operating conditions. Furthermore, the simulations created a distribution of results which was used to calculate confidence intervals and hypothesis tests, hence further increasing the robustness of our findings. The study results were used to produce written testimony to the CSC, oral testimony was provided in late August and early September 2009. (2008-2009) [CSC, Docket 370]
- ***Independent Manager and Expert Witness on selection of resources for the 2006 "All Source" RFP:*** LEI served as the economic advisor to the Connecticut Department of Public Utility Control ("DPUC"), helping them design and implement an "all source" RFP for new capacity in the state in order to mitigate the exposure to ratepayers from Federally Mandated Congestion Costs. As economic advisor and RFP Coordinator, LEI was responsible for managing all aspects of the RFP, including design of innovative financial contracts for capacity, administration of RFP process, and evaluation of bids submitted by project sponsors, and recommendation to the DPUC for selection of winning projects. The selection of projects was based on a proprietary set of models that LEI staff designed to estimate the cost-benefit to ratepayers from long term contracts with new capacity, based on reduction in wholesale market costs across three different ISO New England power markets. LEI also submitted significant written testimony during the 18 months of this engagement, and LEI staff also testified orally on numerous occasions. (2006-2007) [FERC, ER03-563-000]
- ***Standard service auction oversight:*** the DPUC retained the services of LEI to assist it in monitoring the power procurement processes for Connecticut Light & Power's ("CL&P") Transitional Standard Offer auction in November 2004 for services in 2005 and 2006, and in September 2005 to monitor the November 2005 auction for services in 2006. LEI 's mandate included providing advisory services to the DPUC, including guidance on communications protocols, design of sales contract agreement (between CL&P and winning bidders), and also valuation of final bids vis-à-vis the forward market alternatives available to the utility. LEI filed affidavits after the completion of each auction process which the Commissioners used to approve the process and the contracts between CL&P and the winning bidders. (2004 and 2005) [[DPUC, Docket No. 03-07-18PH02]

2.2.2.3 Louisiana

- ***Independent monitor for Entergy New Orleans:*** LEI was engaged by the City of New Orleans to act as the independent monitor for Entergy New Orleans' solicitation of a Third Party Administrator to implement and deliver conservation and demand management programs on behalf of the utility. LEI provided guidance to Entergy and the City on the development of the request for proposals, including mandatory requirements and commercial terms. LEI oversaw the bid receipt, as well as the review and selection process. A final report was submitted to the City, outlining LEI's opinion as to the fairness of the overall process. (2010-2011) [Docket No. R-11-52]

2.2.2.4 Maine

- ***Independent evaluation of the New England Clean Energy Connect transmission project in its sitting proceeding at the Maine Public Utility Commission ("MPUC"):*** LEI was retained in 2017 to advise the MPUC staff on the wholesale electricity market impacts and the macroeconomics effects of the new transmission project on Maine's economy and the economies of other New England states. LEI prepared an independent forecast of future energy and capacity market benefits, carbon emissions reductions, and local GDP and employment impacts as a result of the construction and operation of the project; LEI also critically reviewed the submission of other parties on this topic. After providing written testimony, LEI staff led by Julia Frayer testified at the MPUC in late 2018. [MPUC Docket 2017-00232]
- ***Assessment of Efficiency Maine Trust's submission of its program plan and specifically the avoided cost of energy supply:*** LEI was retained by the Maine Public Utility Commission ("MPUC") to provide an independent forecast of future natural gas prices, wholesale energy and capacity prices, which would be relevant for cost effectiveness analysis of future energy efficiency programs. LEI was also asked to review the multi-stakeholder report that Efficiency Maine Trust and other New England program administrators commissioned in 2014 (and 2015 Update), and subsequently in 2017. LEI staff testified before the MPUC on several occasions over the course of this multi-year engagement. [MPUC Docket 2018-00321]
- ***Advisory to Maine Public Utilities Commission on the costs and benefits of entering into long term contracts for new natural gas pipelines into New England on behalf of electric consumers***: LEI performed evaluation of the costs and benefits of alternatives for expansion of natural gas supply into Maine pursuant to the Maine Energy Cost Reduction Act (MPUC Docket #2014-00071). LEI reviewed and evaluated proposals for firm natural gas transportation service by pipeline developers. LEI performed natural gas network modeling and power simulation modeling to arrive at a quantitative cost-benefit analysis of proposals. LEI submitted reports, responded to discovery from other parties; prepared discovery questions and cross-examined witnesses, reviewed testimony by other parties and provided assessments of the issues presented, and served as an independent expert witness in the proceedings.
- ***Advisory to Maine Public Utilities Commission on Renewable Portfolio Policies:*** LEI presented a written report on the state of renewable portfolio standard ("RPS")

requirements in Maine and regionally across New England. LEI also testified at the Maine legislature. The report was commissioned by the Maine Public Utility Commission to fulfill a statutory requirement to provide research on the issue of RPS and its impact on generators and consumers.

- ***Advisory to Maine Public Utilities Commission on transmission cost allocation (before the FERC):*** LEI advised Maine Public Utilities Commission on methodologies for transmission cost allocation by comparing and contrasting alternative planning approaches and pricing models employed within the US and one international jurisdiction, the United Kingdom. The final report provided a 'strawman' recommendation for an effective cost allocation methodology. (2010) [Docket No. RM10-23-000]
- ***Advisory to the Maine Public Utilities Commission on evaluation of bids in response to legislatively-mandated RFP:*** LEI assisted the Commission on the RFP related to the procurement of electricity in response to statutory mandates and state policy preferences. LEI provided economic analyses of bid proposals by estimating the benefits and costs to the ratepayers, and supported Commission staff in negotiations with short-listed bidders. (2009)
- ***Development of an Electric Resource Adequacy Plan in Maine:*** in Docket No. 2008-104, LEI assisted the Maine Public Utilities Commission in developing an electric resource adequacy plan to aid MPUC in the development of a strategy for the pursuit of the long-term contracts. LEI submitted a report that builds up a set of recommendations for a long-term investment strategy based on an analysis of the current supply-demand situation, a review of the existing wholesale market rules for energy and the Forward Capacity Market, an examination of historical price trends, and review of the investment needs assessments prepared by the utilities and ISO-NE, as well as relevant sub-regional planning studies. (2008) [Maine PUC, Docket No. 2008-104]

2.2.2.5 Maryland

- ***Cost-benefit analysis of minority acquisition of nuclear subsidiary of utility holding company:*** LEI staff submitted testimony on behalf of the Staff of the Maryland Public Service Commission ("MPSC") to the MPSC to conduct a cost-benefit analysis in relation to the proposed transaction between Constellation Energy Group, Inc. ("CEG") and Électricité de France ("EDF") whereby EDF would purchase from CEG a 49.99% interest in Constellation Energy Nuclear Group, LLC ("CENG"). Benefits related to the decreased likelihood of a Baltimore Gas & Electric ("BGE") downgrade, increased likelihood of the Calvert Cliffs expansion being completed and several macroeconomic benefits stipulated to by EDF. Costs related to the limitation on the allocation costs of CEG corporate support services to CENG, increased risk of capital deprivation and reduced quality of service, and implications of CEG's more aggressive nuclear development. (2009) [MPSC, Case No. 9173]

2.2.2.6 Massachusetts

- ***Total Factor Productivity Study and Cost Benchmarking Study for a Natural Gas Utility:*** LEI was engaged by a natural gas utility to assist in an alternative ratemaking proposal for its rate case filing. LEI developed a Total Factor Productivity and Cost Benchmarking Study as support for the proposal.
- ***NTA analysis to relieve concerns regarding transmission reliability:*** LEI was hired to conduct a Non-Transmission Alternatives ("NTA") analysis for the two transmission projects, which are a component of larger transmission solution being proposed by Eversource for the Greater Hartford and Central Connecticut ("GHCC") area. The objective of the NTA analysis was to determine the feasibility and viability of other non-transmission resources – such as new generation and new demand-side resources – to be developed in lieu of these two specific transmission projects to relieve transmission reliability concerns. The NTA analysis [was] filed as part of Eversource's application with the Connecticut Siting Council ("CSC") for each of these transmission projects.
- ***NTA study to assess supply-side and demand-side resources:*** LEI was hired by Eversource to perform a non-transmission alternative study to the Frost Bridge – Naugatuck Valley & Housatonic Valley – Norwalk/Plumtree solution. LEI was asked to evaluate the potential and viability of replacing the solution with supply-side and demand-side resources. Eversource planners have identified two substations within the subarea of study that would be suitable to accommodate an NTA. Under this engagement, LEI reviewed the technical attributes and operational profiles of a range of technologies to evaluate their suitability for resolving overloads and thermal voltage identified by ISO-NE in the SWCT Needs.
- ***NTA analysis to explore generation and demand-side options in Greater Boston:*** LEI was retained to conduct a Non-Transmission Alternatives ("NTA") analysis for the Westfield Reliability project which was being advanced as a solution to reliability problems in the Pittsfield-Greenfield area of Massachusetts by Eversource Energy. The objective of the NTA analysis was to determine the feasibility and viability of other resources - involving new generation and new demand-side resources – to be developed in lieu of the proposed transmission project.
- ***Energy market simulation for MA Energy Facilities Siting Board ("EFSB") regarding the Greater Springfield Reliability Project:*** in response to NU retaining LEI, New England wholesale electricity markets were simulated in order to determine whether the Greater Springfield Reliability Project ("GSRP") would produce economic benefits to the New England region. In order to ensure that economic benefits were not subject to the forced outage and availability schedule of the simulated energy markets, LEI simulated the energy market with 30 different random forced outage and availability schedules. Using these simulations, a distribution of results was used to calculate confidence intervals and hypothesis tests run on the results, hence increasing the robustness of our findings. The study results were introduced as testimony to the EFSB. (2009) [MA EFSB, EFSB 08-2/DPU 08-105/DPU 08-106]

2.2.2.7 Minnesota

- ***Role of Enbridge Line 3 in heavy and light crude oil supplies:*** LEI was engaged as the independent market expert assisting the Minnesota Department of Commerce in evaluating the application of Enbridge Energy for a Certificate of Need for its Line 3 oil pipeline expansion project (Docket No. PL-9/CN-14-916, OAH Docket No. 65-2500-32764). LEI's analysis covered global and local trends in refined product demand and crude oil supply, refinery utilization rates and utilization of high-conversion refinery capacity in Petroleum Administration for Defense District ("PADD") 2 and in the local Minnesota region. LEI's analysis required detailed examination of the assumptions and methodology of an oil pipeline linear programming-based model, in order to assess another witness's testimony which relied on the model. LEI provided written testimony, responded to interrogatory requests, provided written surrebuttal, and provided oral testimony.

2.2.2.8 Mississippi

- ***Management performance audit of large vertically-integrated utility on behalf of the Mississippi Public Service Commission:*** LEI is in the process of performing a two-year engagement to conduct the annual management audits of the fuel and energy procurement activities of Mississippi Power Company, a subsidiary of the Southern Company. The LEI team will assess a complex array of issues including fuel and energy contract terms and the prudency of fuel procurement and inventory practices, and examined the operations of the company's generation fleet. LEI staff will appear before the Commission to present and defend findings.
- ***Management performance audit of large vertically-integrated utility on behalf of the Mississippi Public Service Commission***: LEI performed a two-year engagement to conduct the annual management audits of the oil, gas, coal, nuclear fuel, and energy procurement activities of Entergy Mississippi, Inc. The LEI team assessed a complex array of issues including fuel and energy contract terms and the prudency of fuel procurement and inventory practices. LEI examined the management, organization, controls, strategies, and outcomes of the process that the company relied on for its hourly MISO energy offers. LEI examined the financial implications of a nuclear power plant's outages and the financial implications of the utility's power purchase agreement for nuclear power. LEI staff appeared before the Commission to present and defend findings.

2.2.2.9 New Hampshire

- ***Cost-Benefit and Local Economic Impact Analysis of the Proposed Northern Pass Transmission Project:*** LEI prepared an 11-year energy market price outlook for the New England wholesale power market and forecast the impact of the proposed Northern Pass Transmission project on New England market prices. The project proposes to build a 1,090 MW DC-based transmission line that between Québec and New Hampshire. LEI also

determined the benefits of the proposed project on employment and economic activity in New England. LEI utilized the dynamic input-output ("I/O") economic model developed by Regional Economic Models, Inc. ("REMI") to measure the economic benefits to various New England states from the project on employment, economic activity, and tax revenues. LEI separated the economic impact caused by the construction of the project, and the impact caused by the reduction in energy prices due to the commercial operation of the project, taking into account issues such as usage of electricity in residential, commercial, and industrial sectors in the region. [SEC DOCKET NO. 2015-06]

- ***Testimony on the market mechanics driving New England electric needs and wholesale market trends:*** on behalf of Public Service of New Hampshire, LEI Principals testified in front of the New Hampshire Senate Committee on issue of eminent domain generally and more specifically, on the power market context and near-term outlook for the New England power market and reasons for the development of the Northern Pass Transmission Project.

2.2.2.10 New York

- ***Assessment of carbon emission rates in NYISO markets:*** on behalf of a major power marketer, LEI reviewed various methods of assessing carbon emission rates for electricity imports in the NYISO markets, with a focus on providing the right incentives for low-emission import resources to help NY meet its clean energy targets. LEI presented its findings during the NYISO's April 9, 2018 Integrating Public Policy Task Force meeting**.**
- ***Critical review on competitive retail offering in New York:*** London Economics International LLC ("LEI") was retained by a North American energy retailer to perform a critical review of the New York Public Service Commission ("NYPSC" or "the Commission") Case # 15-M-0127. This proceeding examined whether competitive retail offering from competitive electricity retail providers to mass-market customers should continue and, if so, under what business practices and rules. At the heart of this case was an allegation that competitive electricity retail providers, known as electricity service companies ("ESCOs"), were exercising market power and overcharging New York electricity customers. [Case #15-M-0127]
- ***Assessment of wholesale power market and congestion issues in New York:*** LEI was engaged by a coalition of community groups to prepare an independent outlook of the New York wholesale power market conditions and assess the level of congestion anticipated on major transmission interfaces within the state. LEI Team studied multiple scenarios to illustrate the impact of major drivers on congestion levels. LEI presented the findings at a technical conference organized by the New York Public Service Commission and its report was filed with the PSC in cases 12-T-0502 et al.
- ***Article VII filing for a proposed transmission project:*** LEI was engaged by a private client to support Article VII filing of a proposed HVDC line from Quebec to New York City. LEI Team forecasted 10-year energy and capacity prices, as well as emissions for the New York power market. To support the client's filing, LEI analyzed ratepayer benefits from energy

and capacity market savings as well as emissions reductions as a result of the proposed line. (2009-present) [Case 10-T-0149]

2.2.2.11 Pennsylvania

- ***Merger market power test and merger related cost of capital issues:*** LEI was engaged to provide testimony in opposition to the proposed acquisition. At the Pennsylvania Public Utility Commission, LEI's analysis focused on market power issues and implications for retail markets in Pennsylvania, as well as the impact of changes in the parent company Exelon's cost of capital on the activities of the company's two regulated subsidiaries: ComEd and PECO. [PaPUC, Docket Nos. A-2009-2093057, A-2009-2093058 and A-2009-2093059]
- ***Testimony at Pennsylvania Public Utility Commission on market power issues***: LEI Team filed written testimony on behalf of a US utility in a proposed merger. [PaPUC, Docket No. A-110550F0160]
- ***Review of stranded cost settlement and default supply pricing:*** LEI prepared support for regulatory filing in Pennsylvania assessing benefits to customers from a proposal to extend recovery period for competitive transition charge while extending fixing price for default supply. (2004)

2.2.2.12 Texas

- ***Served as testifying witness on the issue of utility joining a wholesale market:*** Julia Frayer served as testifying witness and lead author in evaluating Entergy's decision to join the Midwest Independent Transmission System Operator ("MISO") Regional Transmission Organization ("RTO") on the behalf of the Public Utility Commission of Texas. LEI evaluated several cost/benefit studies related to Entergy's decision to join MISO over the Southwest Power Pool ("SPP") and provided quantitative and qualitative analysis of specific costs/benefits attributable to ETI and its customers following membership in either MISO or SPP, including but not limited to net trade benefits, transmission cost allocation, governance issues, and continued participation in the Entergy Service Agreement following RTO membership. [SOAH Docket No. 473-12-6206; PUC Docket No. 40346]
- ***Prepared a study of the Value of Lost Load ("VoLL") in ERCOT and evaluated current utility practices for manual load shedding:*** At the request of ERCOT, LEI prepared a report on VoLL, which was filed with the Public Utility Commission of Texas in June 2013 under PUCT Docket 40000.
- ***Peaker Entry Test:*** LEI prepared a report on the Peaker Entry Test ("PET"), LEI relied on its proprietary analytical tool to assess market prices on an ex-post basis, in order to assure that potential market power abilities do not go undetected and unmitigated. The PET compared the revenues earned by a hypothetical gas-fired peaker on the basis of actual market price outcomes to the target full recovery cost (levelized long-run cost) of the hypothetical gas-fired peaker. The report also discussed the automated safe harbor price

benchmark that was part of the PET. The Public Utilities Commission of Texas ("PUCT") eventually adopted a derivative method of the PET for screening for market power in its energy-only markets. (2005-2006) [PUCT, Project No. 24255, Project No. 29042 and Project No. 31972]

- ***PUCT market power issues:*** LEI prepared economic analysis and expert testimony before the PUCT on market power related issues on behalf of one of the largest IOUs in Texas. LEI prepared and filed testimony and quantitative analysis on questions of market definition and market integration. LEI also provided testimony on pricing safeguards proceedings, which looked at alternative market power testing procedures for market power, analyzed implications on investment, and discussed efficiency consequences of certain bidding behavior. (2005)
- ***Pivotal Supplier Test:*** in response to the PUCT's investigation into a client's electric wholesale market activities, LEI conducted a pivotal supplier test ("PST") for the Balancing Energy Services segment of the ERCOT market. (2005) [PUCT, Project No. 24255, Project No. 29042 and Project No. 31972]
- ***PUCT market power:*** LEI assisted a client in the review of the PUCT's Strawman on market power definition issued on August 30, 2004. At the request of the client, LEI conducted a granger-price causality analysis for market definition purposes. The analysis was undertaken to determine both the product and geographical market definitions. (2005) [PUCT, Project No. 24255, Project No. 29042 and Project No. 31972]
- ***Application of SSNIP:*** LEI was retained by one of the largest IOUs in Texas to assess how the hypothetical monopolist's test (also known as the SSNIP test) could be applied for defining the geographical market boundaries for wholesale electricity in ERCOT. (2005)
- ***Market monitoring and mitigation:***, LEI presented its views on market monitoring and mitigation in the context of a PUCT workshop on wholesale market design. Those views reflected LEI's extensive experience in advising on the design and implementation of market monitoring and mitigation policies for wholesale electricity markets. (2005)
- ***Market monitoring issues:*** LEI staff analyzed and modeled the unique concentration ratio method for defining competitive and non-competitive constraints. Subsequently, LEI drafted expert witness testimony on behalf of a market participant analyzing the proposed market power mitigation procedures for the nodal market in the PUCT proceeding to adopt the nodal protocols. This analysis critically reviewed the various schemes used by other ISOs for day-ahead bidding restrictions, and also considered the efficacy of the nodal market proposal put forward by stakeholders vis-à-vis reasonable power plant remuneration. (2005)
- ***Standard Market Design:*** LEI examined issues related to the Standard Market Design ("SMD") proposed by the Federal Energy Regulatory Commission ("FERC") and its implications for ERCOT and a large IOU in Texas. LEI assisted the client in the preparation of comments for submission to FERC in response to their SMD proposal. In the course of producing these comments, LEI evaluated SMD's specific proposals and benchmarked them against best practices worldwide. (2005)

2.2.2.13 Utah

- ***Monitor for PacifiCorp's Renewable Solicitation Process:*** LEI staff were part of a consortium that served as the Independent Evaluator for PacifiCorp's renewable solicitation process (to acquire wind and solar power). The Independent Evaluator reported to the Utah Public Service Commission. This process included reviewing and assessing the overall solicitation process(including both documentation and modeling methodologies); assessing: the valuation of the bidder pre-approved process; development of review criteria, monitoring, auditing, and validation of bid evaluation process; bid evaluation; contract negotiation; and preparation of reports. (2008-2009) [Public Utility Commission of Oregon, Docket No. UM1368]

2.2.2.14 Vermont

- ***Macroeconomic impact of a solar generation facility:*** LEI prepared a written testimony to the State of Vermont Public Service Board on the economic benefits that a proposed solar project. The testimony includes macroeconomic impact to Vermont using the JEDI Project PV model.
- ***Testimony on proposed merger between Central Vermont Public Service and Green Mountain Power:*** for a small independent power producer, LEI prepared a testimony on the potential harms of the proposed merger to the client and proposed certain conditions for the Vermont Public Service Board to consider. (2012) [PSB Docket No. 7770]

2.2.3 Testimony provided to regulators in Canada

2.2.3.1 Alberta

- ***Assisted with Capacity Market Design Proceeding:*** LEI supported a power generator in Alberta through the AUC process to review provisional market rules for the new capacity market. Work entailed analysis of specific policy topics (such as economic withholding), drafting of expert testimony, review of other participant submissions, testimony, etc. [Proceeding # 23757]
- ***Estimation of the spot market and the forward market impacts around the discretionary timing of outages by large generation owner in Alberta:*** LEI was engaged by a law firm on behalf of a Canadian electricity transmission company to provide market advisory in relation to an ongoing Market Surveillance Administrator investigation related to the timing of outage scheduling under PPAs. Work involved providing an understanding of the regulatory practices in other energy markets around the world, with respect to market participant behavior in offering energy and capacity from power plants, intertie scheduling, portfolio bidding, and outage scheduling. [Proceeding #3110]
- ***Expert witness at the AUC regarding Export Tag Timing:*** LEI served as the expert witness in a proceeding at the AUC on behalf of TransAlta related to TransAlta's export scheduling process, and helped assess the reasonableness of the proposed penalty. [AUC Proceeding No. 1553; Application No.1607868]

- ***Testimony in support of transmission operating rules and curtailment protocols for interties into Alberta:*** Julia Frayer provided testimony in support of transmission operating rules and curtailment protocols for interties into Alberta, as proposed by the Alberta Electricity system Operator ("AESO") in order to support a fair, efficient and openly competitive power market. The testimony was made in front of the Alberta Utilities Commission ("AUC"), on behalf of Morgan Stanley Capital Group ("MSCG"), a customer of the Montana–Alberta Transmission Line. Julia's analysis considered commercial as well as operating protocols in deregulated power markets and considers how market rules incentivize new entry and produce dynamic efficiency gains related to more intense competition. The AUC issued a favorable decision to MSCG in early 2013. [AUC Proceeding No. 1633]
- ***ENMAX RRO Return Margin Dec 2013:*** LEI provided an expert opinion regarding an appropriate return margin for the Regulated Rate Option service providers ("RSP"), which was filed with the Alberta Utilities Commission as evidence in the proceeding to review the RSPs' current energy price setting plans ("EPSP"). LEI concluded that a reasonable return margin could be established using a benchmarking method, and that competitive electricity retailers in Alberta were the most appropriate peer set against which to benchmark RRO returns. LEI recommended a comprehensive return margin, expressed in $/MWh, calculated using the average competitive retailer mark-up as a base and adjusting for customer acquisition costs. [AUC Proceeding No. 2941; Application No. 1610120]
- ***Evaluation of proposed Load Following Service ("LFS") procurement auction***: LEI provided an independent evaluation of the proposed LFS auction by ENMAX Energy Corporation, including evaluation of the both the product being auctioned and the auction mechanism and key parameters. The LFS product as proposed to be auctioned was meant to represent the "shape risk" in the Regulated Rate Option ("RRO") service. LEI's evaluation considered whether the product and auction mechanism would result in an efficient, competitive and fair outcome for the Alberta market, RRO providers, potential suppliers of the auctioned product, and customers of the RRO service. LEI prepared a report titled "Independent assessment of proposed market-based determination of shape risk in RRO supply", which was filed with the Alberta Utilities Commission ("AUC"). [AUC Proceeding ID No. 2941; Application No. 1610120]
- ***Testimony on performance-based ratemaking:*** LEI provided a supporting testimony for FortisAlberta Inc., a Canadian electricity utility, in its filing for a performance-based ratemaking ("PBR") plan. The testimony provided detailed data analysis (including inflation and TFP trends), underpinning PBR economic theory, and reviews of best practices in various North American and International jurisdictions. The testimony offered back up elements for each of the various components of the PBR plan proposed by FortisAlberta, Inc. (2011-2012) [Alberta Utilities Commission, Proceeding ID 566]
- ***Design of incentive rate structure for Alberta utility:*** for Enmax, a large metropolitan Alberta utility, LEI advised on design of a proposed incentive based rate structure, including a multi-year term, operating cost incentive structure, and earnings sharing mechanism. Deliverables aided in development of regulatory filings and included

testimony before the Alberta Utilities Board. [Alberta Utilities Commission, Application ID: 1550487, Proceeding ID: 12]

- ***White paper analysis for stakeholders in response to Alberta Department of Energy's regulations on market power:*** in response to government proposed policies on what defined a "fair, efficient, and openly competitive" market, LEI prepared a detailed white paper and market analysis on the proposed market power tests to be added regulation, and specifically demonstrating the adverse effects of the 20% hard cap market share limit proposed by Department of Energy ("DOE"). White paper was filed as testimony with the DOE in their consultation on Section 6 of the Electric Utilities Act. [AUC Proceeding No. 21115; Application No. 21115-A001]
- ***Design of incentive rate structure for Alberta utility:*** for a large metropolitan Alberta utility, LEI advised on design of a proposed incentive based rate structure, including a multi-year term, operating cost incentive structure, and earnings sharing based mechanisms. Deliverables aided in development of regulatory filings and included testimony before the Alberta Utilities Board. [AUC Proceeding No.566; Application No.1606029]
- ***Served as expert advisors to council & testifying witnesses TransAlta Class Action 2018:*** LEI was retained to provide a layperson's explanation of how the retail electricity market works in Alberta, including a comparison to the wholesale market. This included information on different customer classes and how these different classes pay for different products, as well as additional information such as the number of customers and typical electric consumption and payment terms of different customer classes. The deliverable was used to understand the potential impact on certain consumers in a class action lawsuit against an Alberta generator. [AUC Proceeding No.3110]
- ***Review of valuation metrics used in conjunction with tax payment challenge for an Alberta generator:*** assessed the appropriateness of valuations utilized to determine depreciation deductions related to the acquisition of a coal- fired generating station. Engagement also required creating forecasts that would have been appropriate at the time acquisition was made several years previously, as well as calculating asset values using multiple valuation approaches. Multiple forecasting tools were used. Engagement included developing critiques of work by opposing expert witnesses. [AUC Proceeding No. 192; Application No.1600863]

2.2.3.2 Nova Scotia

- ***Assisted in formulation performance standards:*** LEI was retained by the Nova Scotia Utility and Review Board ("UARB") to act as an independent consultant to the Board assisting in the formulation of performance standards for Nova Scotia Power Inc. ("NSPI") in the areas of system reliability, storm response and customer service. LEI prepared and submitted a Consultation Paper followed by a technical workshop with stakeholders. The LEI team also responded to various interrogatories and submitted a rebuttal report. LEI testified as an independent expert in Halifax at the oral hearing in September 2016.

2.2.3.3 New Foundland and Labrador

- ***Review of electricity regulation in New Foundland and Labrador:*** LEI was engaged by the Commission of Inquiry Respecting the Muskrat Falls Project to serve as an expert to the Inqury. LEI's scope of work consisted of preparing a report addressing the following topics: a comparison of Newfoundland and Labrador's electricity regulation system relative to other jurisdictions; assessing the system's ability to deal with challenges stemming from interconnection, including energy marketing; exploring the province's energy policy; recommending changes to the province's electricity pricing model; and assessing the potential role for renewable energy generation expansion.

2.2.3.4 Manitoba

- ***Review of utility rate application:*** LEI was retained by Hill Sokalski Walsh Olson ("HSWO") to provide independent evidence to assist the Manitoba Public Utilities Board ("PUB") in understanding the views and positions of the general service small and general service medium ("GSS/GSM") customers in Manitoba Hydro's 2017/18 & 2018/19 general rate application ("GRA") proceeding. In a PUB letter dated September 15, 2017, the scope of LEI's role was expanded to include key issues for the Keystone Agricultural Producers ("KAP"). LEI's analysis included the impact of the proposed rate increases of GSS, GSM and agricultural ratepayers, Manitoba Hydro's capital plan, and a review of the utility's operating efficiencies and service quality.

- ***Supported Manitoba cost of service review:*** LEI was retained by Hill Sokalski Walsh Olson LLP, at the request of Manitoba Public Utilities Board, to represent the interests of small commercial customers in its review of Manitoba Hydro's cost of service review. LEI performed an extensive review of Manitoba Hydro's cost of service model, proposed changes and all related procedural documents.

2.2.3.5 Ontario

- ***Testimony on community expansion***: LEI was retained by Union Gas Limited to provide expert assistance on the potential economically efficient approaches to community natural gas distribution expansion within Ontario. LEI performed a cross-jurisdictional assessment of community expansion cases across North America, with a particular interest in the types of cross-subsidization policies employed.

- ***Prepared total factor productivity study and presented testimony in respect of Ontario Power Generation's ("OPG") hydroelectric incentive ratemaking plan:*** LEI was retained by OPG to assist in the development of its first generation IRM plan, following the formulaic I-X approach. LEI prepared an industry study of TFP trends spanning the North American hydroelectric sector. LEI also recommended an inflation index, which reflected cost drivers relevant to OPG while also aligning with the regulatory precedent in Ontario. LEI testified before the Ontario Energy board. LEI's analysis supported the successful approval of OPG's first generation IRM plan for its regulated hydroelectric fleet. [OEB EB 2012-0340]

- ***Provided an analysis of building block incentive ratemaking approach and their applicability to Enbridge, a natural gas distribution utility in Ontario:*** LEI's report supported the client's distribution tariff proposal submission to the Ontario Energy Board ("OEB") for a second- generation Customized Incentive Regulation ("IR") plan for the period of five years (2014-2018). The testimony set out the theory behind as well as the practical experience of using the building blocks approach in incentive regulation regimes. Julia Frayer appeared before the OEB for cross examination. [OEB File No. EB-2012-0495]

- ***Cost of capital for regulated generating assets:*** LEI provided expert testimony on behalf of the Ontario Energy Board regarding risk factors associated with Ontario Power Generation's prescribed assets, as well as creating a risk-return continuum on which power sector assets could be placed. [OEB, proceeding ID: EB-2007-0905]

- ***Advice on performance-based ratemaking:*** LEI provided expert testimony on behalf of the Coalition of Large Distributors in Ontario on 3rd generation Incentive Regulation Mechanism proceedings of the Ontario Energy Board. The work involved testimony filed with the Board with detailed analysis of the theory behind the various components of PBR system, including inflation and efficiency gains factors, treatment of capital expenditures among others. The analysis was supplemented with comparison of actual factors and indices, and determination of the more robust and appropriate indices for the Ontario's distribution industry, including total factor productivity analysis for the sector. [OEB, EB-2007-0683]

- ***Presentation to the Ontario Energy Board ("OEB") on regulatory options for setting payments for the output from Ontario Power Generation's prescribed assets:*** Oral presentation was a follow up on a written submission provided by LEI to the OEB on alternatives for regulating prices associated with output from designated generation assets in Ontario. [OEB, proceeding ID: EB-2006-0064]

- ***Comments on OEB's consultation paper on benchmarking of distribution companies***: Julia Frayer provided comments on the benchmarking methodology suggested by OEB consultants, looking at the analytical aspects of defining and benchmarking the performance of multiple utilities across long period of time. The critique provided details on how each criterion affects the benchmarking study and what are the remedies available to improve the results. [OEB, EB-2006-0268]

- ***Conservation and Demand Management (C&DM) in Ontario:*** LEI prepared testimony related to the alternative ratemaking approaches available regarding C&DM; and addressed innovative alternatives and compared and contrasted various schemes in the Ontario context. [OEB, Proceeding ID: RP-2004-0188]

- ***Cost of Capital for regulated generating assets:*** provided expert testimony on behalf of the Ontario Energy Board regarding risks factors associated with Ontario Power Generating's prescribed assets, as well as creating a risk- return continuum on which power sector assets could be placed.

- ***Conservation and demand management ("C&DM") in Ontario:*** wrote testimony related to the alternative ratemaking approaches available regarding C&D; addressed innovative alternatives and compared and contrasted various schemes in the Ontario context.

2.2.3.6 Quebec

- ***Expert testimony before the Quebec regulator (Regie) in Fall 2005 on transmission related issues:*** In the context of a transmission rate case and consideration of alternative transmission rate designs, Julia Frayer led the economic analysis for an IPP investigating the impact on trade from increased transmission costs, involving multi-factor regression analysis of nodal electricity prices, price spreads across markets, and interchange flows (imports and exports) across borders. Julia also considered the impact of the elasticity of demand for transmission services between Canadian provinces and US markets in the Northeast for maximizing revenues in rate setting. [Regie, Docket No. R-3459-2004]

2.2.4 Commercial litigation

- ***Power contract dispute:*** LEI was engaged by a law firm in Kansas City to prepare an expert report in support of litigation in Case 15CV-04225 in the District Court of Johnson County, Kansas. LEI examined the value of the green attributes of landfill gas ("LFG") produced by a project in Kansas City and sold under long-term contract to the Sacramento Municipal Utility District ("SMUD"). LEI's report demonstrated several flaws in the opposing counsel's expert's methodology. LEI proposed an alternative, more appropriate methodology for valuing the green attributes of LFG, based on market fundamentals driven by the California RPS requirements. LEI staff were deposed.
- ***PPA contract dispute:*** LEI provided expert witness service for a private equity investor in matter related to a contractual dispute regarding a long-term power purchase agreement between a municipal utility located in New England and a landfill gas generator. LEI analyzed the key contractual terms of the PPA and providing an expert's review of how those terms compared to the industry norm when the contract was signed and became effective. LEI also provided an independent estimate of potential contractual damages. [Commonwealth of Massachusetts Superior Court Department, Civil Action No. PLCV2006-00651-B]
- ***PPA contract dispute:*** LEI prepared an expert report for a utility in a dispute over contract valuation as of a certain date. LEI analyzed the contract and the broader economic environment and market fundamentals to determine the value of the PPA as of that date. The analysis involved economic modeling to provide energy market price, volume and revenue forecasts. LEI also valued the contract using cost, market and income valuation approaches.
- ***PPA contract dispute:*** LEI prepared an expert report for a utility in a contract dispute with a municipal authority. The companies had signed a power purchase agreement obligating the utility to make a portion of the capacity of a generating plant available pursuant to defined pricing and other terms. LEI analyzed the contract and the broader economic and commercial environment to determine if sale of the plant constituted a breach of the agreement.

- ***Review of Dutch electricity market regulatory dynamics:*** in a case between a US utility and the US heard in the Federal Court of Claims, LEI testified in deposition and trial, and provided understanding of how Dutch electricity market was structured in the mid-1990s, how it was expected to evolve, and how it did actually evolve. Issues addressed included market structure, regulation, role of non-utility investors, and role of private and international investors. [Court of Federal Claims, Case No. 06-305T]

- ***Examination of Swiss electricity market:*** for a US financial institution, LEI reviewed the development of the Swiss electricity market and specifically the position of hydro stations within that market. Analysis included a discussion of the factors that influence the value of hydro stations, presence of foreign owners in the Swiss electricity market, and use of post-tax cash flow to evaluate potential investments. [Court of Federal Claims, Case No. 06-587]

- ***Assessment and valuation of quantum merit claims:*** for advisor and developer of biomass facilities, LEI provided expert opinion on value of services provided based on industry knowledge, review of correspondence, and experience providing or commissioning similar services. [Civil Action, Docket No. CV-06-705]

- ***Valuation of PPAs associated with IPPs in Thailand:*** as an expert witness in an arbitration case, LEI quantified the change in value resulting from modifications to several PPAs associated with a power project in Thailand. Engagement included review of PPAs, evaluation of Thai power sector restructuring process, extensive modeling of financial aspects of PPAs, and assessment of financing alternatives; client won on all claims. [International Chamber of Commerce International Court of Arbitration, Case No. 11593/DB (C 11528/DB)]

- ***Contract damage assessment and expert witness testimony submitted in mediation process between the client and counterparty:*** from the perspective of gas suppliers, LEI analyzed the extent to which the new DCR ("DCRnew") as proposed by the Ontario Electricity Financial Corporation ("OEFC") was a good replacement for the regulated Direct Customer Rate ("DCR") to direct industrial customers when used for the purposes of escalating gas commodity charges in gas supply contracts to Ontario non-utility generators.

- ***Material adverse change:*** LEI examined the economic grounds for requesting a renegotiation of a swap contract. The analysis hinged on an assessment of whether a modification to a market participant's offer strategy for one of its generators constituted a "disruption event."

- ***Review of valuation metrics used in conjunction with tax payment challenge for an Alberta generator:*** assessed the appropriateness of valuations utilized to determine depreciation deductions related to the acquisition of a coal-fired generating station. Engagement also required creating forecasts that would have been appropriate at the time the acquisition was made several years previously, as well as calculating asset values using multiple valuation approaches. Multiple forecasting tools were used. Engagement included developing critiques of work by opposing expert witnesses

- ***Analysis of potential customer impacts due to holding company acquisition of merchant generator:*** discussed ways in which customer rates would be impacted by potential credit rating downgrades of regulated subsidiaries due to holding company parent's acquisition of merchant generator; engagement included examination of impact on default supply as well as reliability

2.3 Market power filings to FERC

- ***Merger analysis in support of the NRG, Inc. and GenOn*** merger: LEI staff, under Julia Frayer's direction and guidance, performed Delivered Price Tests analysis for FERC under Section 203 of the Federal Power Act and submitted extensive analysis to FERC in the summer of 2012. The Merger Application was successfully approved by FERC in December 2012. Subsequently, LEI assisted the client in preparation of the 205 market-based rate authority analysis. [FERC Docket. No EC12-134]
- ***Triennial market power analysis (southeast region):*** LEI performed Pivotal Suppliers Analysis and Market Share Analysis for the Entergy balancing authority area in support of a client's application to renew market-based rate authorization under the provision of FERC. (2011) [ER97-4281, et al.]
- ***Triennial market power analysis (northeast region):*** LEI performed Pivotal Suppliers Analysis and Market Share Analysis for the Northeast region, including New England, New York, PJM as well as the Connecticut, NYC and PJM East submarkets in support of a client's application to renew market-based rate authorization under the provision of FERC. (2011) [ER97-4281, et al.]
- ***Triennial market power analysis (northeast region):*** LEI performed Pivotal Suppliers Analysis and Market Share Analysis for the Northeast region, including New England, New York and PJM in support of a client's application to renew market-based rate authorization under the provision of FERC. (2011) [ER10-2895, et al.]
- ***Buyer market power analysis and vertical market power analysis:*** LEI analyzed the potential competitive market effects on a vertical scale and considered the extent of buyer market power for the purchase of standard service (full requirements) products in support of a client's opposition of a proposed electric transmission and distribution utility merger in the Northeast US. LEI also supported the client at FERC [EC11-35-000].[1] (2010-2011)
- ***Merger related market power analysis:*** LEI evaluated the PJM market and considered the competitive effects of the proposed the merger of FirstEnergy and Allegheny, in light of current and evolving market conditions for PJM West area. LEI's analysis contributed to the negotiated, confidential settlement between certain parties. (2010) [EC10-68-000]
- ***Updated market power analysis:*** LEI analyzed a client's market power in PJM and ISO-NE for a US utility's triennial review of market-based rate authorizations for certain subsidiaries in the northeast region. (2010) [ER98-4159, et al.]

[1] LEI's white paper was not filed with FERC but was relied upon by the client when they filed protest.

- ***Section 203 and 205 analysis in support of NRG's acquisition of certain Dynegy assets in CAISO and ISO-NE:*** LEI was engaged to provide testimony in support of a proposed acquisition. LEI performed a Delivered Price Test ("DPT") for CAISO and ISO-NE energy markets as well as a standalone Herfindahl-Hirschman Index ("HHI") analysis for the capacity markets. In addition, LEI discussed the impact of the acquisition of the ancillary services markets. (2010) [EC10-88-000]

- ***Section 203 and 205 analysis in support of an asset acquisition in the Entergy control area:*** LEI was engaged to provide testimony in support of a proposed acquisition in Entergy's control area. LEI conducted a change in HHI analysis as well as an analysis of the acquirer's net load position for a Section 203 filing. LEI also conducted the Section 205 analysis and showed that with the acquisition, the client still passes the pivotal supplier and market share screens. (2010) [EC10-86-000]

- ***Updated market power analysis:*** LEI analyzed the client's market power in CAISO for a US IPP's triennial review of market-based rate authorizations for certain subsidiaries in the southwest region. (2010) [ER99-115, et al.]

- ***Critique of market power allegations in California during the Energy Crisis***: LEI served as advisor to a Canadian-based electricity supplier related to allegations of market power abuse during the California crisis period; LEI examined and critiqued the underlying analysis for the related cases at FERC from the US Court of Appeals, as well as the complaints filed by the California parties. (2010) [EL01-10-000, et al.]

- ***Preparation of analysis for generation market power under FERC's indicative screens for market based rate authorization:*** LEI performed an updated market power analysis for acquirer's affiliates in the California ISO which have been granted market-based rate authorization, and prepared the related Section 203 filing in support of the acquisition of a 21 MW photovoltaic solar facility. (2010) [ER10-204-000]

- ***Merger market power test - PJM:*** LEI was engaged to provide testimony in opposition to a proposed acquisition. LEI performed a preliminary Herfindahl-Hirschman Index ("HHI") test for market power for all regions affected, and a Delivered Price Test ("DPT"), including a more detailed HHI test, for the PJM East and ComEd regions. In addition, LEI examined post-merger optimal bidding strategies using our proprietary model of strategic behavior, known as CUSTOMBid. (2009) [EC09-32-000]

- ***Merger related cost of capital issues:*** LEI assessed the impact of changes in the parent company's cost of capital on the activities of the company's two regulated subsidiaries. LEI estimated the impact on customer costs from potential debt downgrades following the merger, and assessed the effectiveness of proposed ring-fencing measures. (2008-2009) [EC09-32-000]

- ***Updated market power analysis:*** LEI analyzed the company's market power in the southeast region using FERC market power screen analysis for a US generator's southeast triennial review of market-based rate authorizations for certain subsidiaries. (2008) [ER02-1572-000, et al.]

- ***Updated market power analysis:*** LEI analyzed the company's market power in several markets, including the control area of the Bonneville Power Administration ("BPA"), New England (ISO-NE), New York (NYISO), and PJM RTO (PJM) for a Canadian asset manager's triennial review of market-based rate authorizations for certain subsidiaries. (2008) [ER08-1125-001]
- ***Updated market power analysis prepared for a New Jersey corporation***: LEI was retained to update the corporation's market power analysis in conjunction with its market-based rate authorization granted by FERC. The company owns generating facilities in the PJM control area. The client passed all screens and maintained its MBRA from FERC. (2008) [ER99-1293-010, et al.]
- ***Triennial review of Market-Based Rate Authorization:*** for an Ohio paper manufacturer, LEI analyzed market power of several of the company's power generating subsidiaries. The assignment included the analysis of the control area of the Bonneville Power Administration, New England (ISO-NE), New York (NYISO), and PJM RTO (PJM). For the same client, LEI prepared initial market-based rate authorizations for two subsidiaries located in the Midwest control area (MISO). The client passed all screens and received its MBRA from FERC. (2008) [ER-06-761-003, et al.]
- ***Market Based Rate Authorization filing for a plant in the Midwest:*** for a Canadian power marketer, LEI analyzed the Midwest market, and the relevant first tier regions, to assess the implications of the power marketer's acquisition of a new power plant. (2007) [ER07-1330-000]
- ***Market Based Rate Authorization filing for a plant in the Pacific Northwest:*** for an independent power producer ("IPP"), LEI analyzed the Pacific Northwest market, and the relevant first tier regions, to assess the implications of the IPP's acquisition of a new power plant. (2007) [ER07-527-000]
- ***Analysis of Midwestern merger implications for market power:*** for a municipal utility in the Midwest, LEI analyzed the merging companies' market power filings to FERC and conducted an internal analysis of the market power implications of the merger. LEI prepared memos for the client, who ultimately decided not to submit a complaint to FERC regarding the merger. (2007)
- ***Market power testimony in February 2006, on behalf of a municipal power authority, protesting a proposed acquisition of a 300 MW power plant:*** LEI concluded that the mitigation offer, as it was proposed, was inadequate in size and scope due to the potential for strategic behavior and generation market power abuses. (2006) [EC06-48-000]
- ***Market Based Rate Authorization filing for a hydro asset in Maine:*** LEI analyzed the New England market, and the relevant first tier regions, to assess the implications of the IPP's acquisition of a new hydroelectric facility in Maine for an independent power producer. The IPP passed all screens and received its MBRA from FERC. (2006) [ER06-784-000]
- ***Analysis of regulation for Market Based Rate Authorization filing for New England hydro assets:*** LEI analyzed the potential for market power in the market for regulation in

ISO-NE as part of a market power analysis for the potential acquisition of a set of hydroelectric plants in the Northeastern US. (2005) [ER05-454-000]

- ***Updated market power analysis:*** LEI analyzed the New England market, and the relevant first tier regions, based on FERC's codified methodology for a New England generator. The generator passed all screens and received its MBRA from FERC. (2005) [Docket No. ER99-1522-004]
- ***Support regarding market power concerns against a proposed merger:*** LEI was retained by a leading law firm to conduct quantitative analysis regarding a pending acquisition and to submit testimony about this analysis to FERC. The scope of the project included analysis of potential post-merger market power in pertinent markets and recommendations on required mitigation that would be sufficient to cure market power screen failures. (2005) [EC05-43-000]
- ***Market Based Rate Authorization filing for Nevada industrial generation:*** LEI supported one of the world's largest gold mining companies in its MBR filing to FERC following its decision to develop a power plant near its industrial operations in Nevada. As part of this project, LEI analyzed the level of competition within the Sierra Pacific Control Area to demonstrate that the client did not have market control in this or any neighboring regions. The client ultimately received its MBRA for this facility. (2005)
- ***Market Based Rate Authorization filing for a major New England generator:*** LEI supported a client, one of the largest generators in New England, who had received a deficiency letter following its submission for updated market-based rate making authority. The work entailed reviewing all previous submissions, analyzing the New England market, and developing a revised MBR filing that addressed all of FERC's concerns and questions. LEI's analysis was ultimately approved by FERC in June 2005. (2005) [ER05-665-001]
- ***New England Market Based Rate Authorization filing:*** for a Canadian industrial conglomerate, LEI supported the acquisition of a New England hydroelectric facility by demonstrating to FERC that the client would not possess market power in New England as a result of this transaction. The client received its MBRA. (2005) [ER06-1446-000]
- ***Market Based Rate Authorization filing for PJM assets:*** LEI supported a Canadian conglomerate in its acquisition of several assets located in PJM. LEI demonstrated to FERC that the client did not possess market power in PJM as a result of the proposed transaction. (2004) [ER05-639-000]
- ***Market Based Rate Authorization filing for a New England portfolio:*** LEI supported a client in its application for MBRA by conducting analysis to demonstrate to FERC that the client did not possess market power in New England. (2004) [ER04-994-000]
- ***Market Based Rate Authorization filing for a New York hydro portfolio:*** for a Canadian IPP, LEI analyzed the market power implications of the acquisition of some 70 hydroelectric plants in New York using the FERC market power screen analysis. LEI demonstrated that the IPP did not have market power as a result of this acquisition and the IPP obtained its MBRA. (2004) [EC04-120-000]

- ***Triennial filing for Canadian power marketer:*** LEI conducted the research and analysis required to prepare a Triennial Review for a Canadian power marketer that owns various power generation assets in the US. LEI's analysis demonstrated that the company did not possess market power as per FERC's required market power screen analysis. (2004) [ER02-2397-000]

- ***Section 203 filing for NY generation assets:*** LEI prepared analysis for a FERC filing under Section 203 of the Federal Power Act, related to a proposed acquisition of generation assets by an IPP. The application showed that this transaction was in the "public's interest" - primarily by demonstrating that there were no unmitigated negative competitive effects stemming from the proposed transaction. LEI's objective was to meet the specific analytical requirements of the Merger Policy Statement, including the Horizontal Screen Analysis (otherwise also known as the Competitive Screen Analysis). In addition to the concentration ratio calculation and delivered price test that were completed under the competitive screen analysis, LEI conducted basic simulation modeling of the strategic bidding potential in the relevant power market. (2002)